Eastern Renewable Generation Integration Study

Technical Review Committee

February 5, 2014

Aaron Bloom

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NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

Opening: Kenny Gruchalla

- Intro to Energy Systems Visualization
- Safety and security
- Rest rooms
- Web and phone participants

Agenda

Morning

- Project Overview
- 2010 Simulations
- 2026 Simulations
- NREL High Performance Computing
- HPC Tour

Afternoon

- Solar Data Review
- Net Load Analysis
- Reserves Analysis
- Sensitivities Discussion
- 4-Month Plan

NREL Team

- David Palchak
- Clayton Barrows
- Marissa Hummon
- Greg Brinkman
- Kara Clark
- Anthony Florita
- Andrew Weekly
- Caroline Draxl
- Jack King
- Gary Jordan

Disclaimer

- **This document is for discussion and development purposes only. Any data or statements contained in this document are subject to revision without notice. Do not cite or quote. Contact aaron.bloom@nrel.gov with any questions.**

Recap: ERGIS

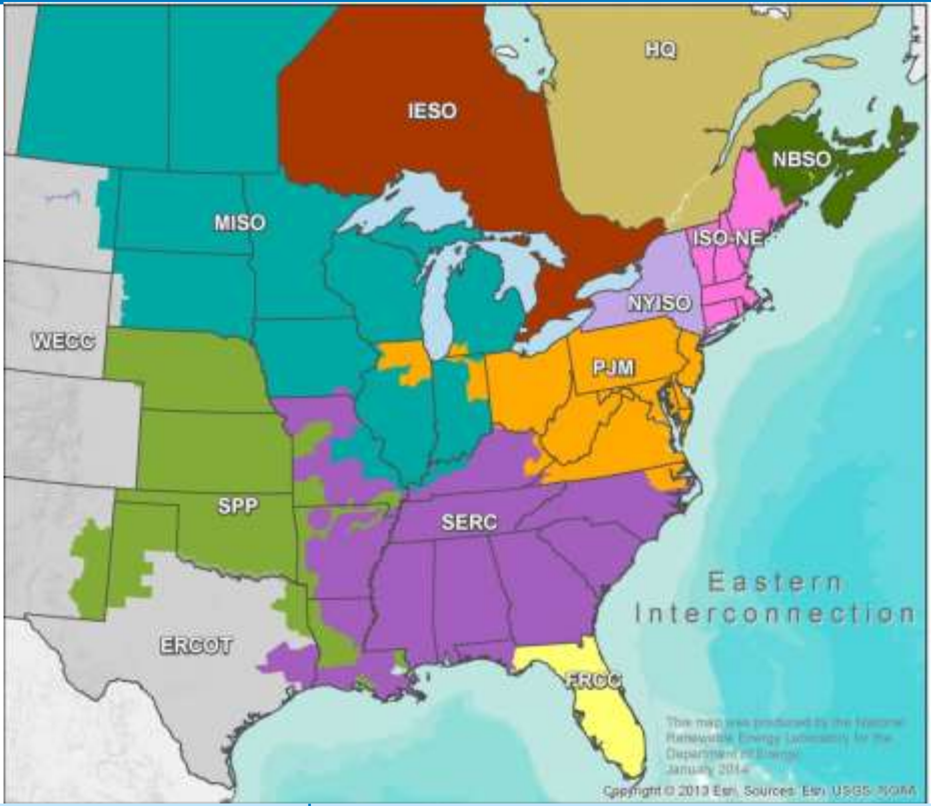
- **Motivation**
  - How do high penetrations of solar and wind generation impact system operations of the Eastern Interconnection?
- **Approach**
  - Assemble a Technical Review Committee to guide the development of a database that accurately characterizes the Eastern Interconnection. Then use an advanced mixed integer model to analyze renewable generation at a sub-hourly resolution.

Operational Areas of Interest

- **Reserves**
  - Types
  - Quantities
  - Sharing
- **Commitment and Dispatch**
  - Day-ahead
  - 4-hour-ahead
  - Real-time
- **Interchange Scheduling**
  - 1-hour
  - 15-minute
  - 5-minute

Scenario Overview

- Designed to:
  - Bookend two approaches to renewables
    - National policy implementation
    - Regional policy implementation
  - Highlight impact of additions of renewables
- Generation expansion using ReEDS



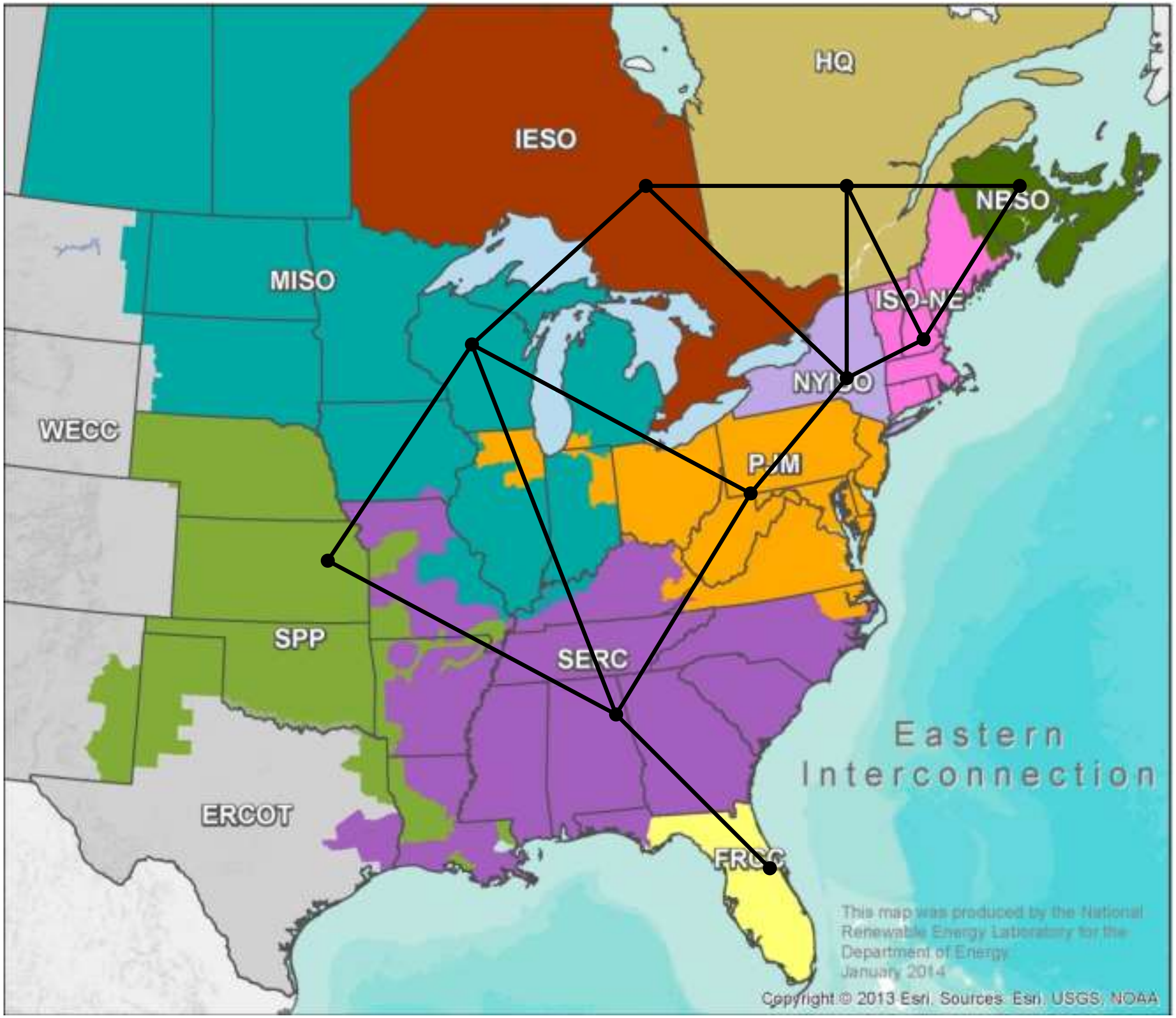
	Energy Penetration (%)		Solar PV Capacity (GW)		Wind Capacity (GW)		Conventional Capacity (GW)			
Scenario	Solar	Wind	Rooftop	Utility	Onshore	Offshore	Nuclear	Coal	CC	CT
Low Renewables	0	3	0	0	23	0	88	208	185	187
State RPS	0.2	12	1	2	95	8	88	195	175	198
Regional 30%	10	20	70	104	149	27	88	182	154	145
National 30%	5	25	35	52	199	16	88	171	173	153

2010 Simulations

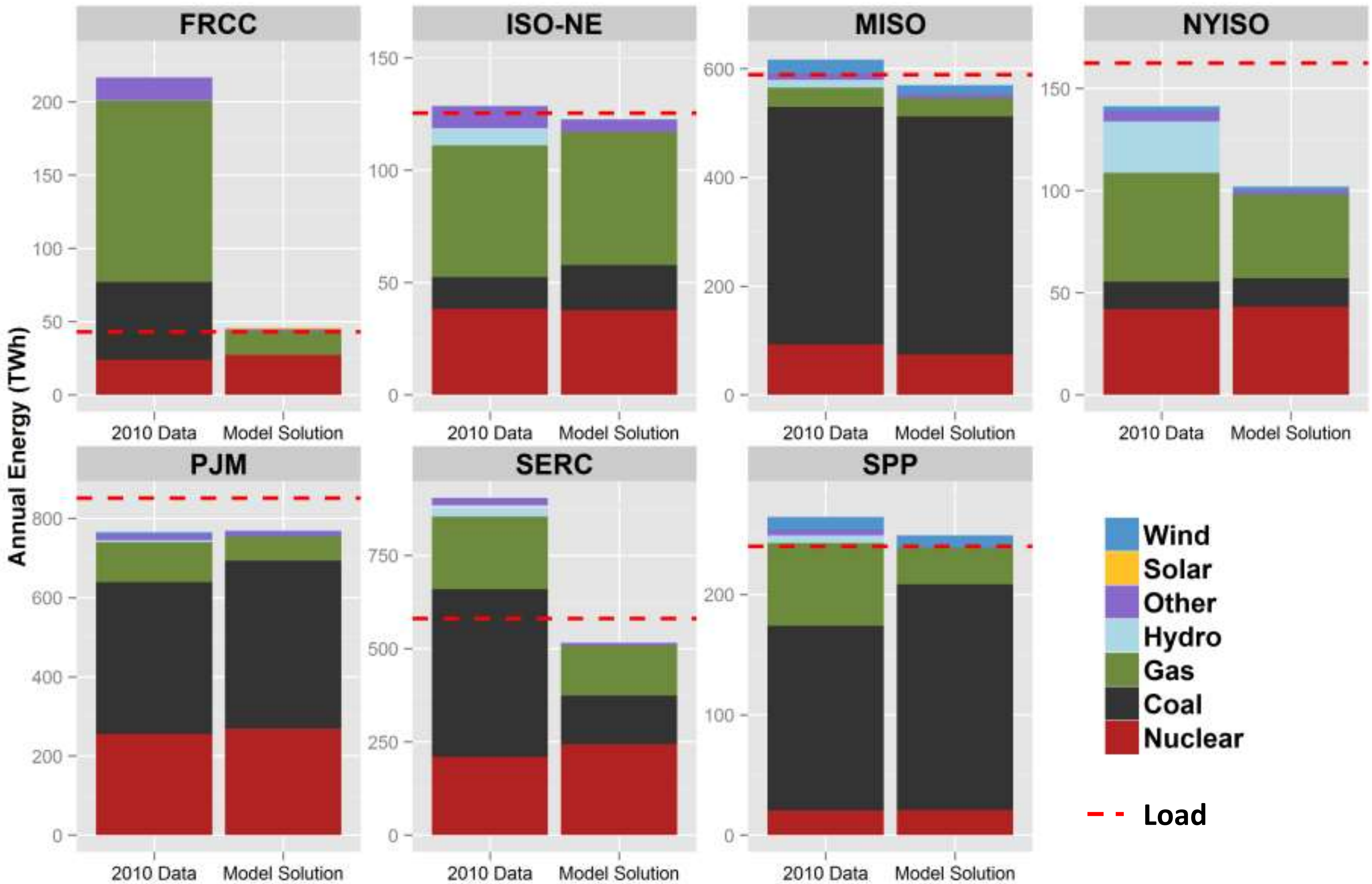
2010 Benchmarking Activities

- **Simulated the EI in a variety of ways and compared to 2010 EIA data**
- **Day-ahead only**
- **9 EI regions plus Hydro Quebec**
- **Simplified reserves requirement for each EI region**
  - 2.5% of load
  - 10 minute response time
- **Transmission model varies by run**

Initial Transmission Model



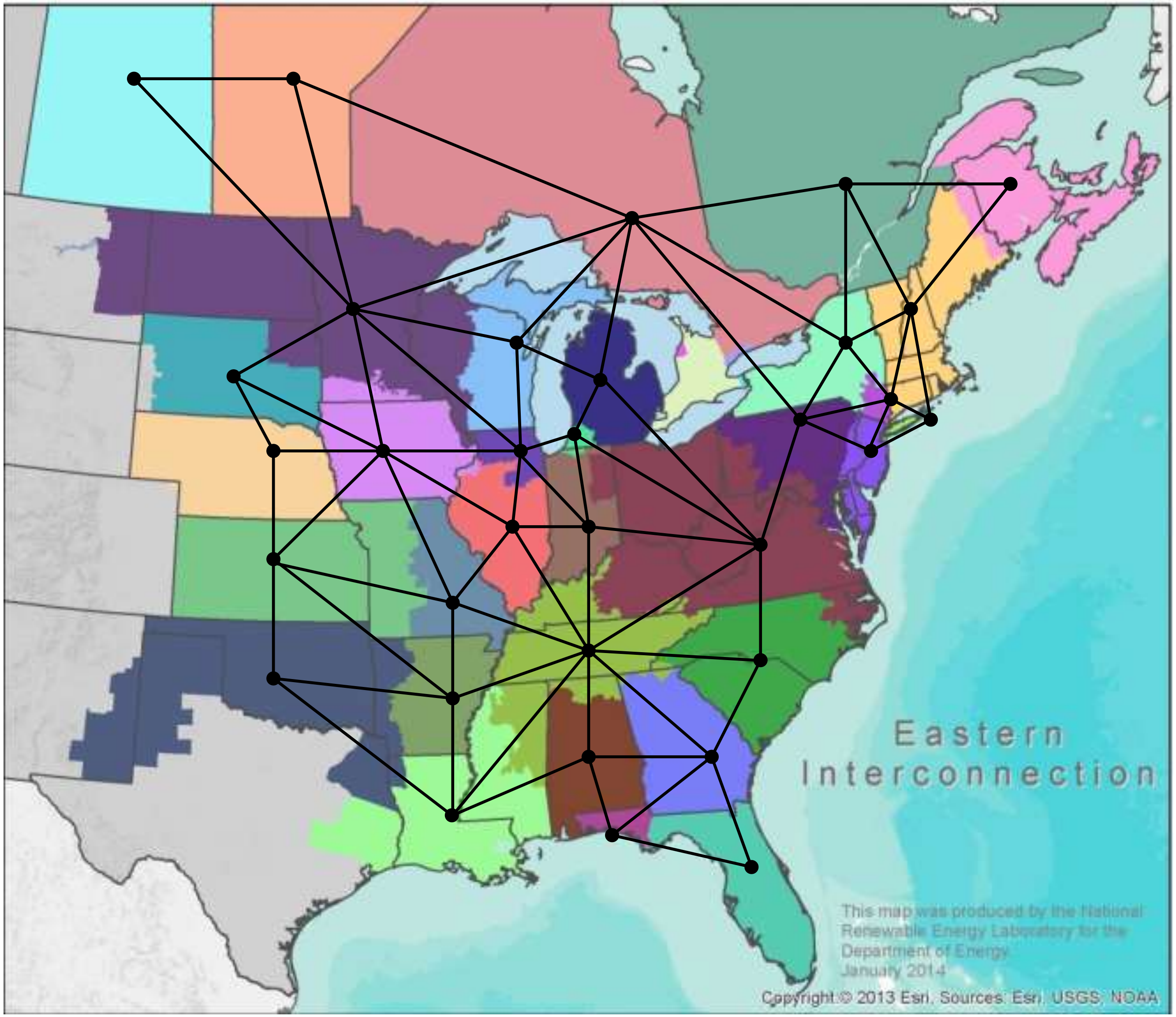
Initial Results—Generation by Region



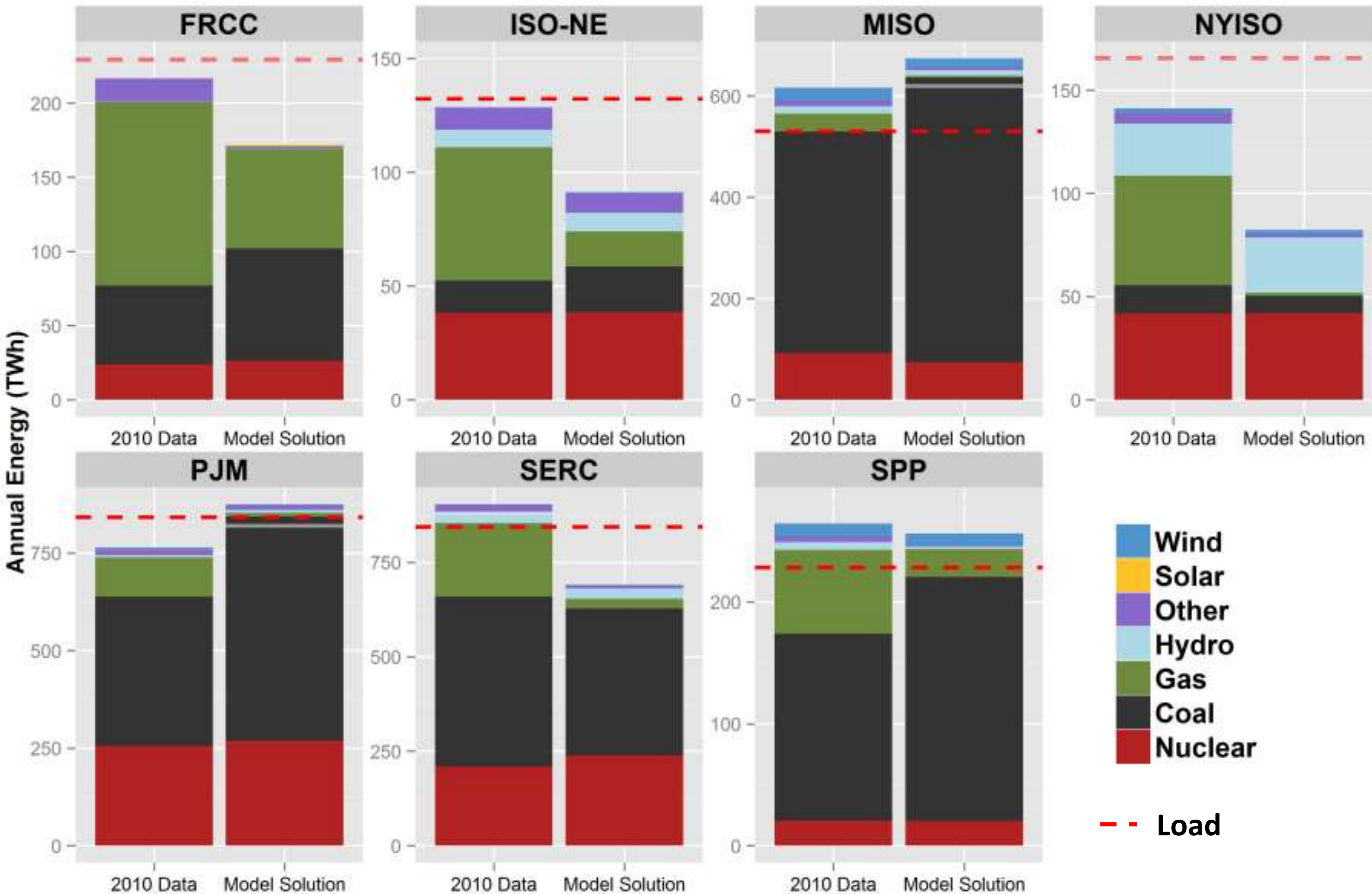
Data Revisions for November TRC meeting

- **Major data revisions**
  - Transmission zones
  - Load values
  - Fuel prices
  - Hydro constraints
- **Plus other smaller data revisions**

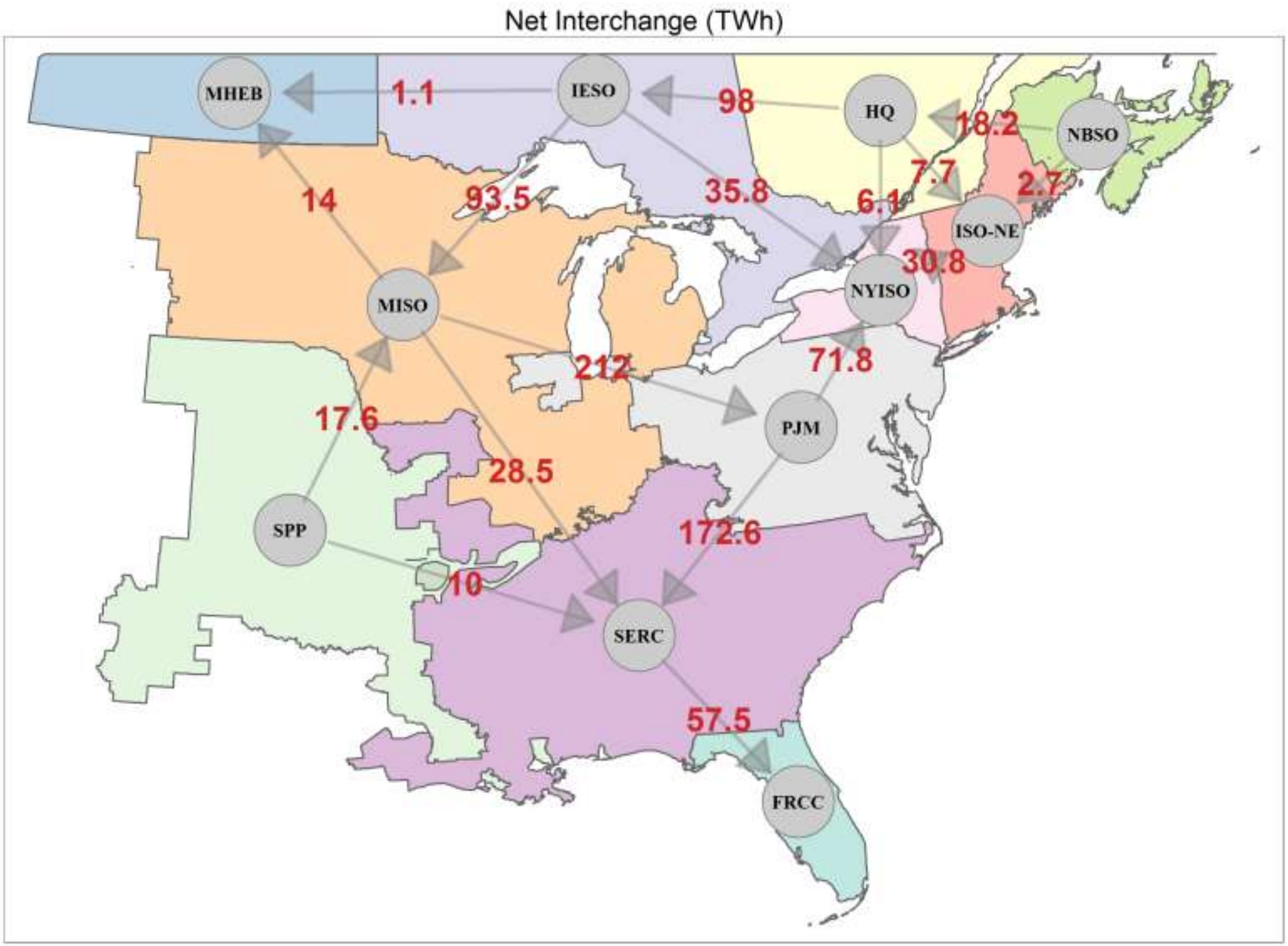
Second Transmission Model



Nov. TRC Meeting—Generation by Region



Nov. TRC Meeting—Net Interchange Flows

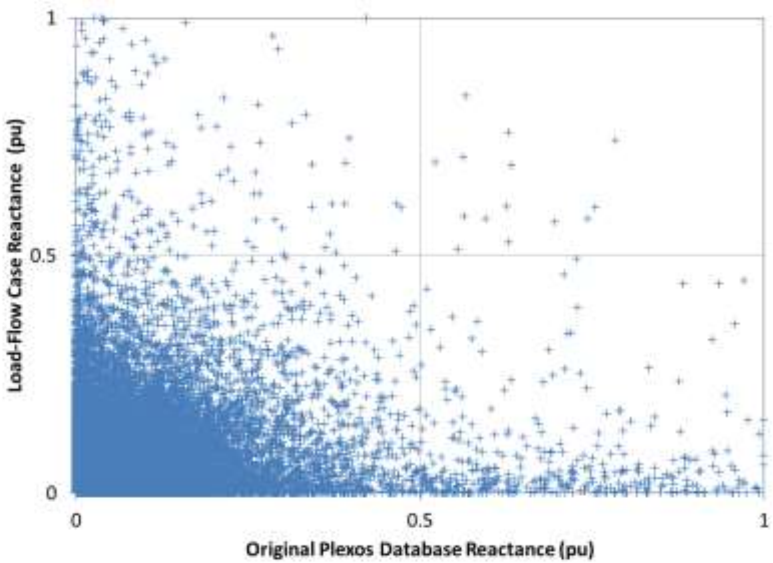


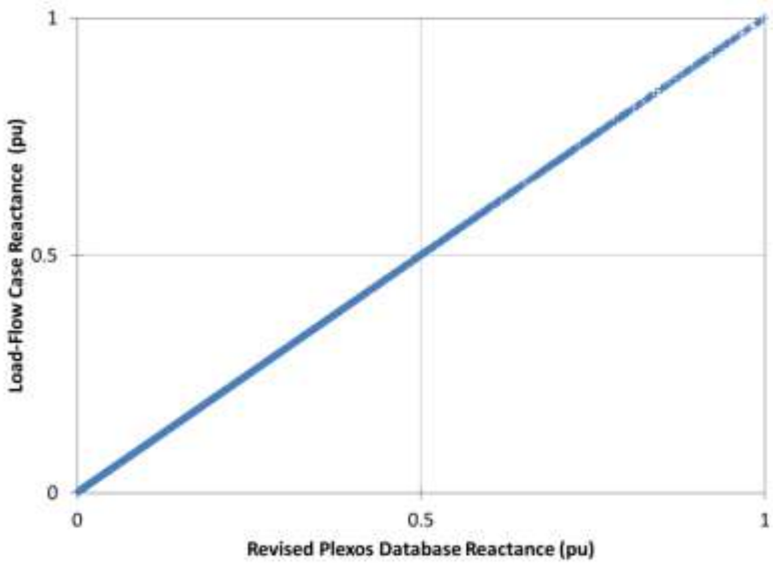
TRC Conclusions from Nov. Meeting

- **Generation mix reasonable with reasonable transmission limits**
- **Some regional interchanges questionable (too high)**
- **33-node network too simplistic**
- **Network equivalencing not desirable**
- **Long runtimes with full EI network acceptable**
  - Promise of HPC parallelized solutions

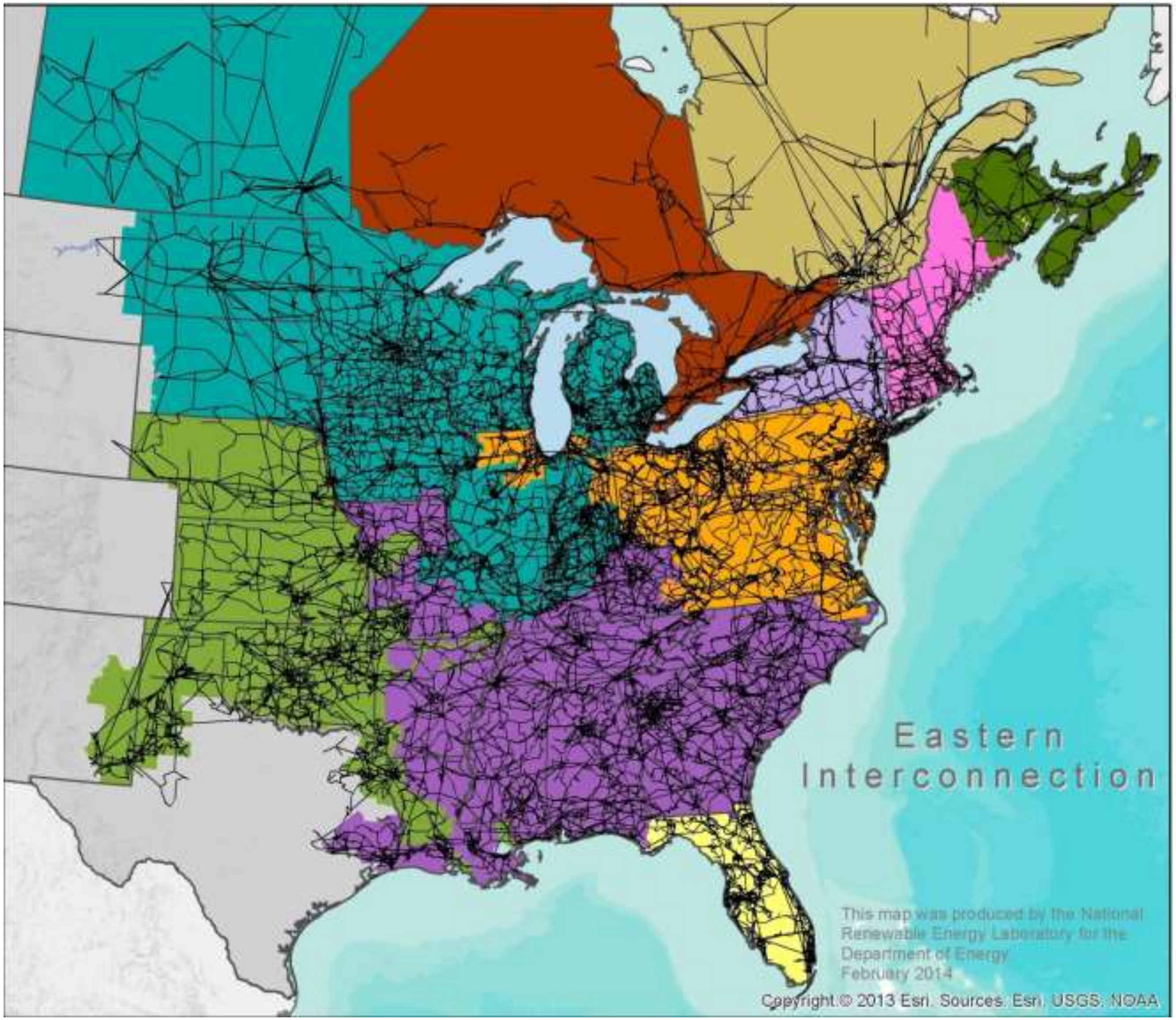
Correction of Transmission Properties

- **Found that most transmission elements had incorrect electrical properties**
- **Corrected with properties from MMWG load-flow case**





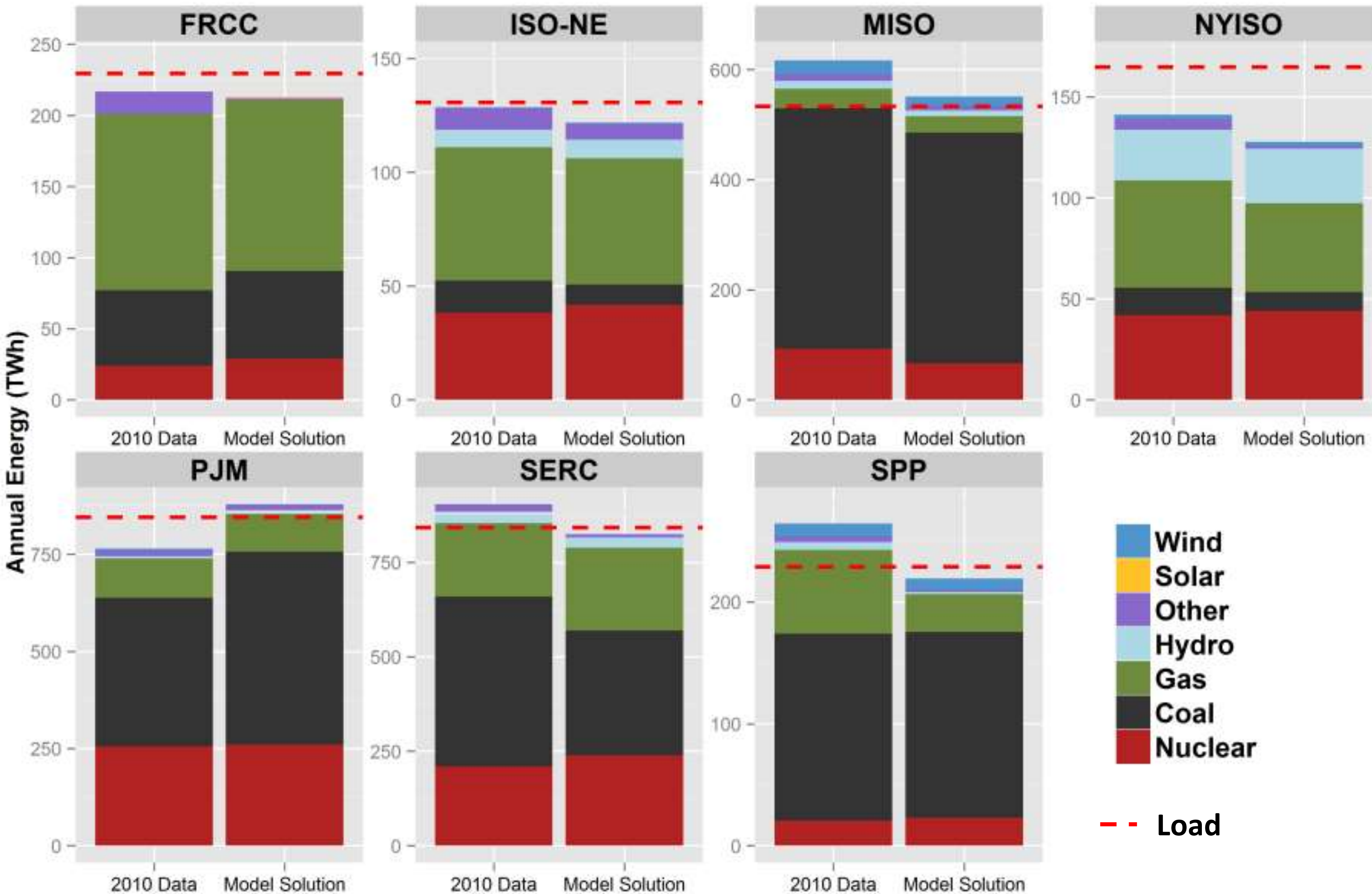
Full Nodal Transmission Model



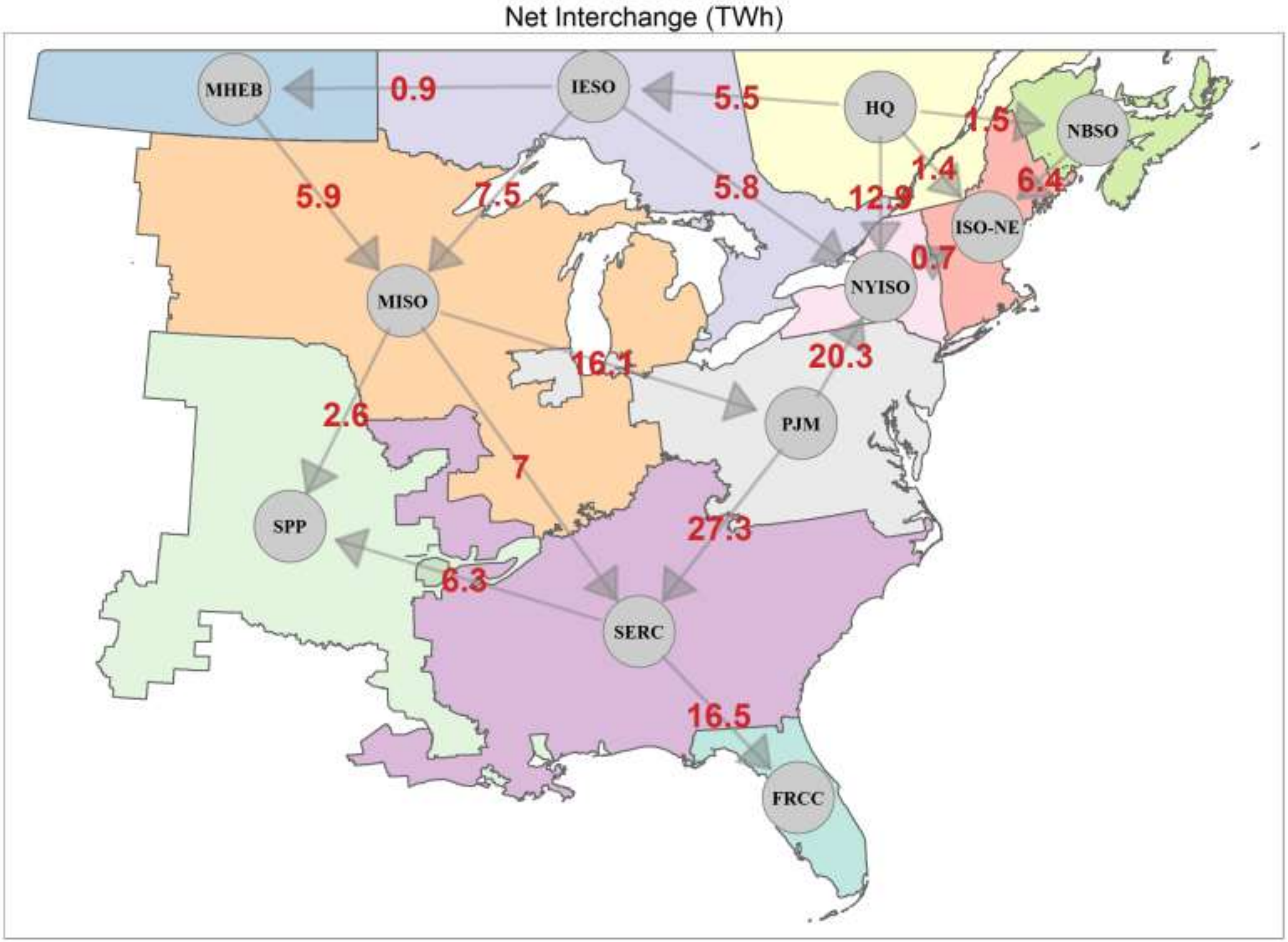
Transmission Limits

- **Not feasible to monitor and enforce all transmission line limits**
  - Too many constraints
  - Most not binding (therefore not important)
- **Iterative process to determine which lines function as flowgates**

Latest Results—Generation by Region



Latest Results—Net Interchange Flows



Considerations

- **Reference data is not exact**
  - Generator-level EIA data aggregated by zip code to ERGIS regions—poor performance at regional borders
- **Imperfect knowledge of actual costs and generator availability**
  - Heat rates, fuel costs, VO&M, start-up costs
  - Generic generator outage rates rather than actual 2010 outage patterns
- **Non-economic dispatch in actual operation**
  - Independent optimization of each region
  - Out-of-market dispatch

Conclusions from 2010 Benchmarking

- **Generation mix by region is reasonable**
- **Transmission flows between regions are reasonable**
- **Approximately 20 major iterations/revisions to the model to achieve reasonable flows and generation mix**
    - Approximately 100 runs required for testing and debugging
    - Rapid update cycle now achieved by varying model resolution and using established analysis methods

Study Year Simulations

Study Year and Scenarios

- **Study year is nominally 2026**
- **Four scenarios**
  - Current wind and solar
  - State RPS build-out
  - National 30% penetration
  - Regional 30% penetration

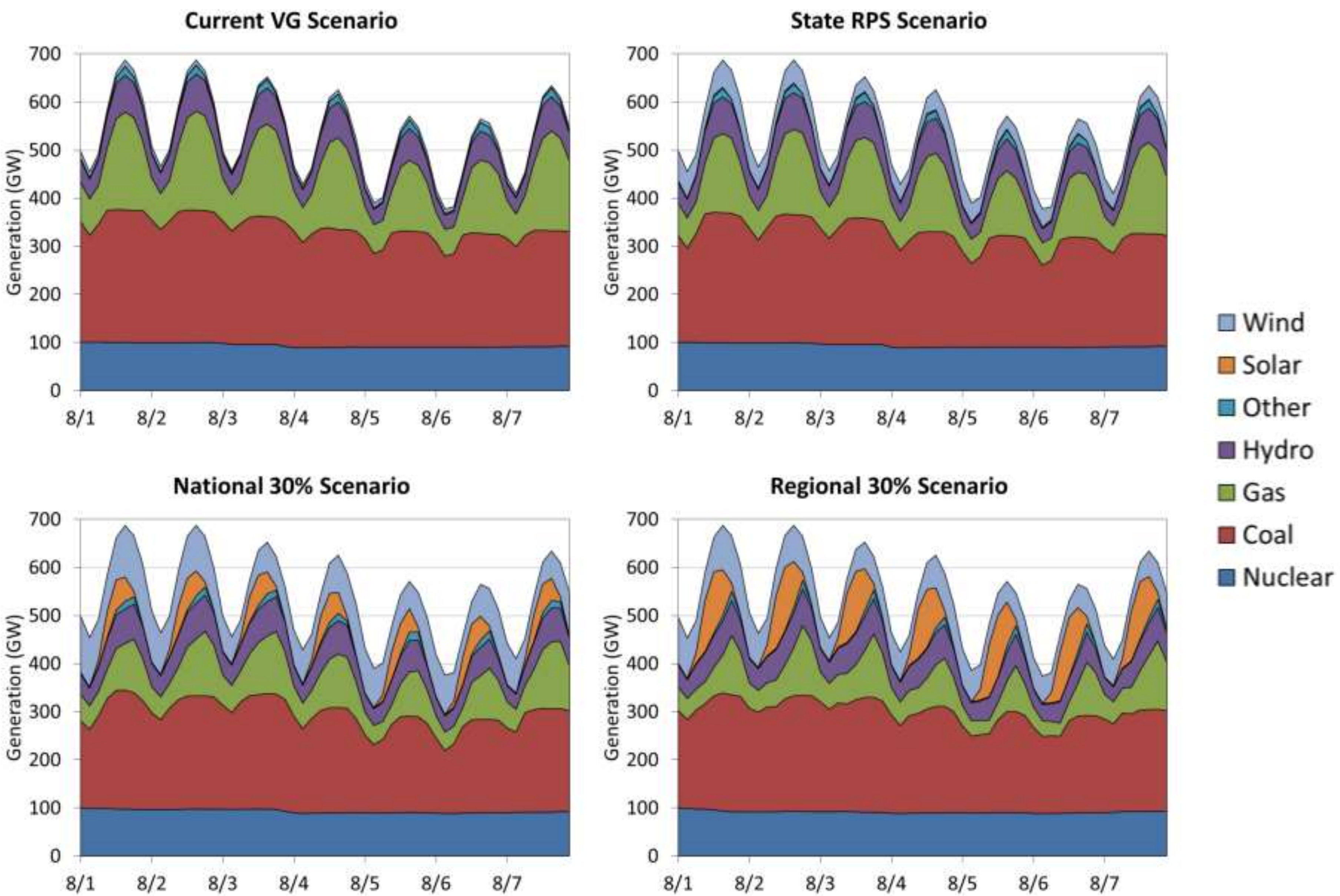
Database Modifications for Study Year

- Thermal fleet retirement and expansion
- Transmission expansions
- Wind and solar expansions
- Load
- Ancillary services
- Fuel prices

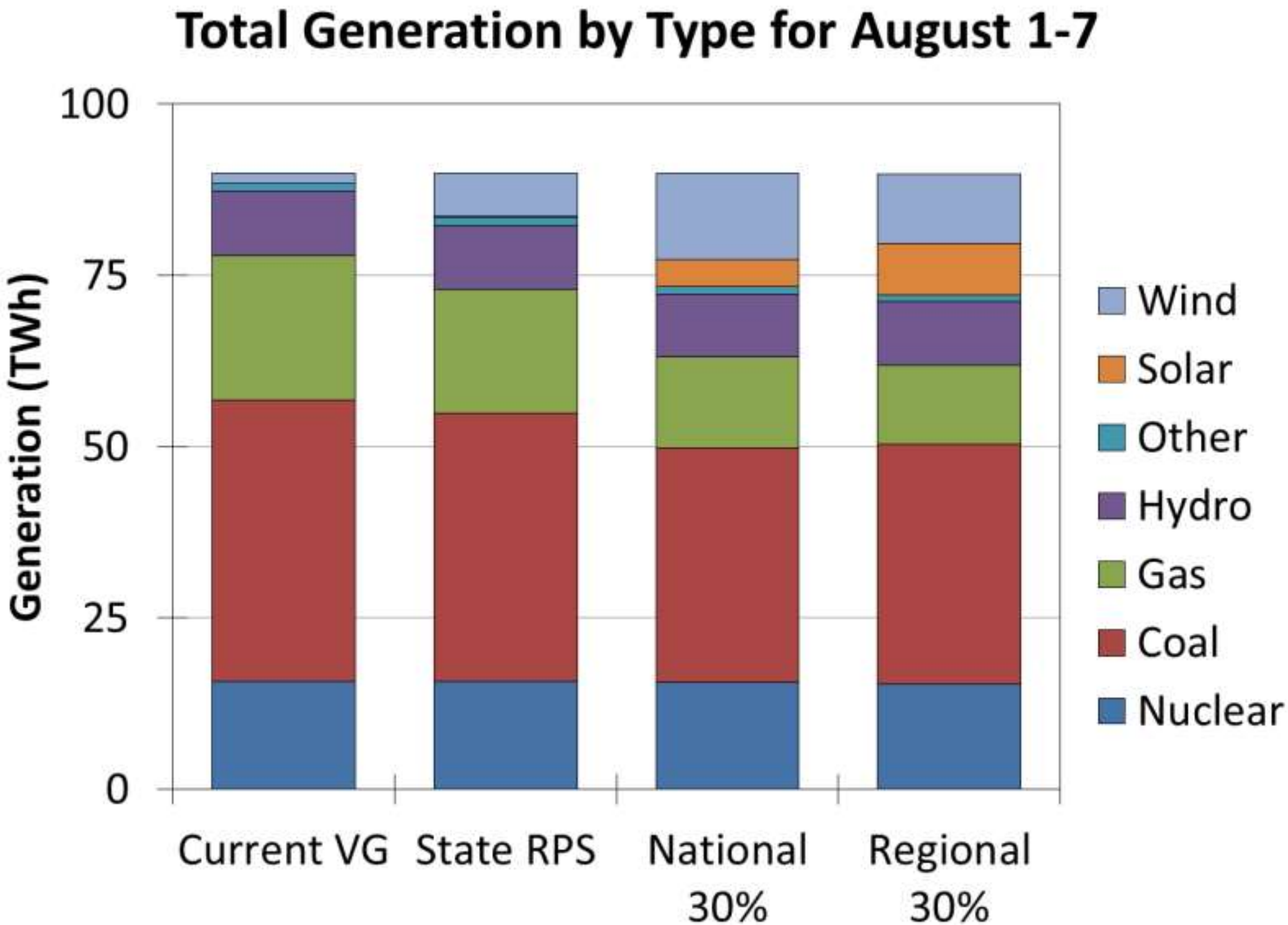
Study-Year Simulations

- Currently testing all four scenarios
- Selected weeks in January, April, and August
- Day-ahead only
- Simple place-holder reserves product
- Plan is to continue increasing resolution of the four scenario models

Study-Year Simulations: Initial Results

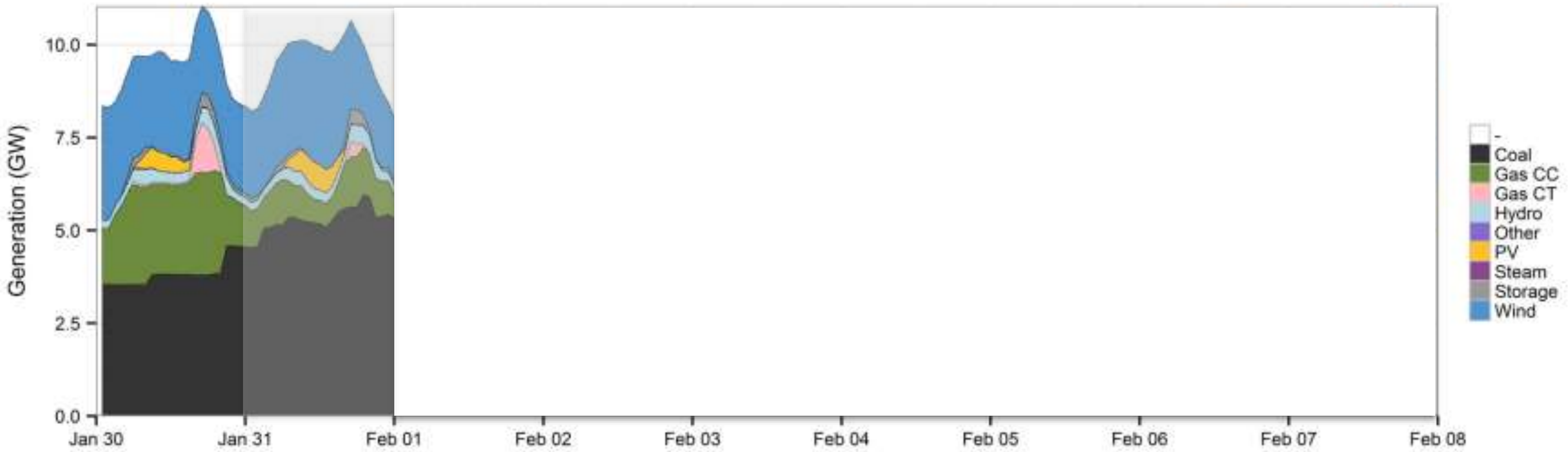


Study-Year Simulations: Initial Results



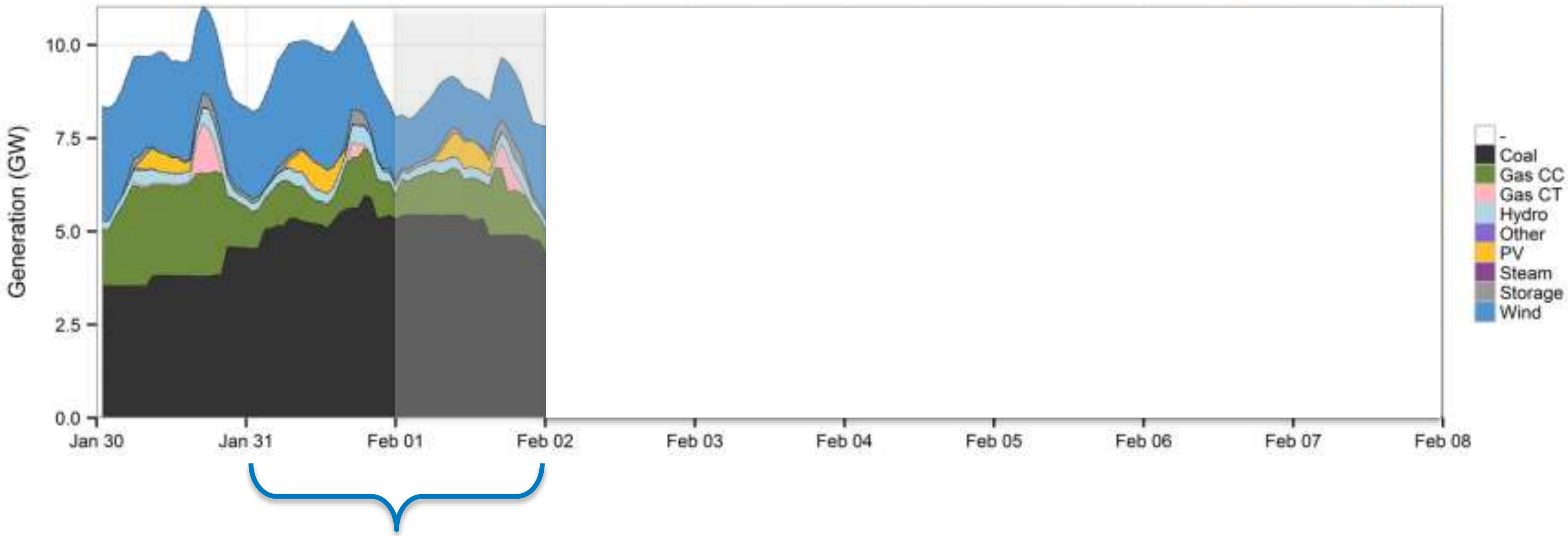
High Performance Computing

Unit Commitment and Economic Dispatch



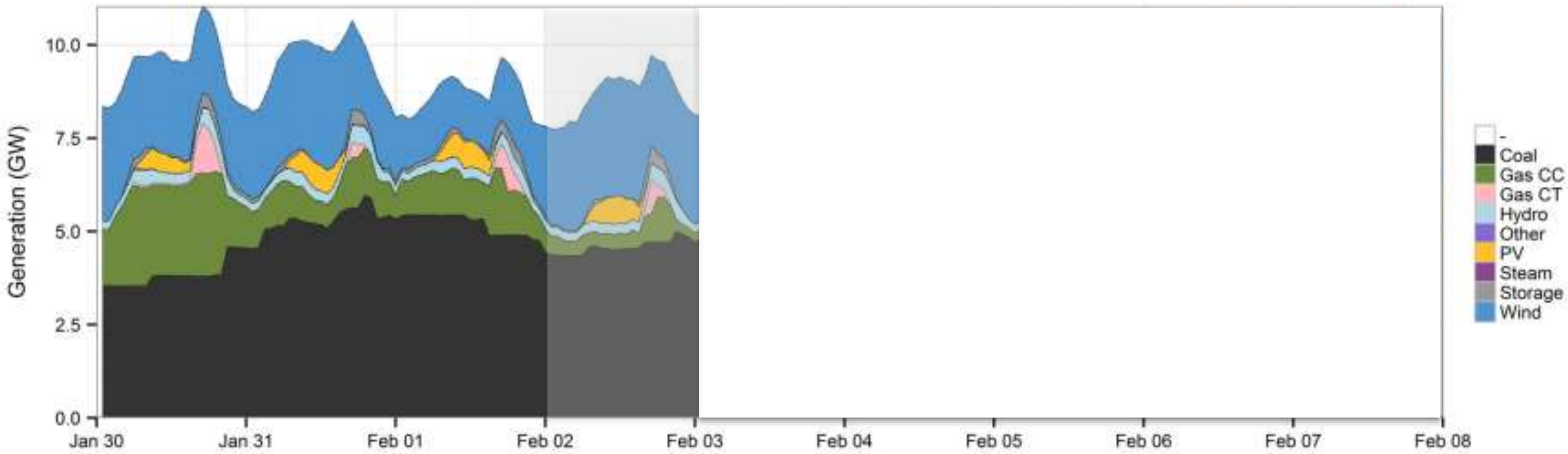
optimization horizon:
48 hours

Unit Commitment and Economic Dispatch



rolling forward in
24 hour increments

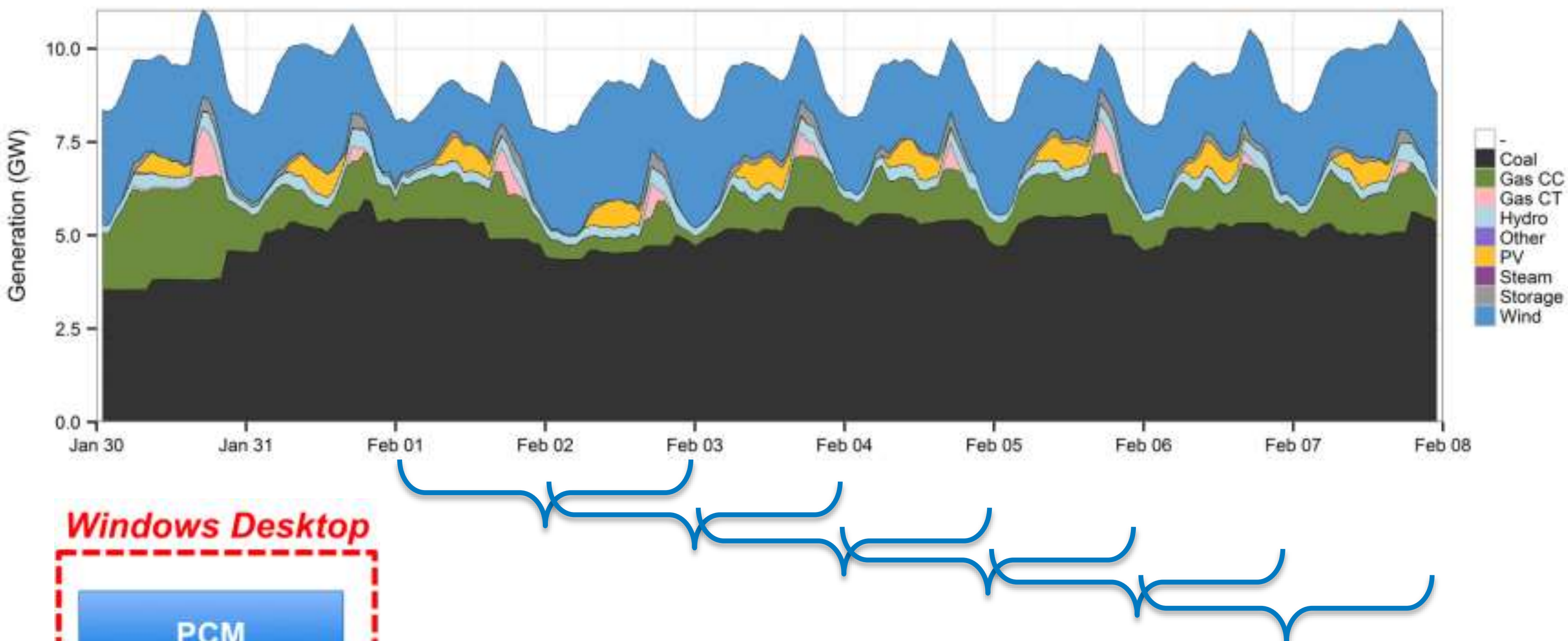
Unit Commitment and Economic Dispatch

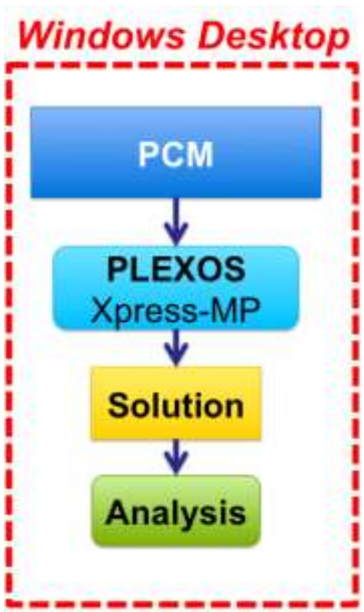


The state of the system at time t=0 is dependent on:

1. Generator commitment status: on/off
2. If “on”: hours of continuous operation; current ramp rate
3. If “off”: hours since last operation (minimum shut down duration)

Unit Commitment and Economic Dispatch





Each optimization problem takes between 2 minutes and 7 hours to solve.

Annual solutions can range from hours to weeks.

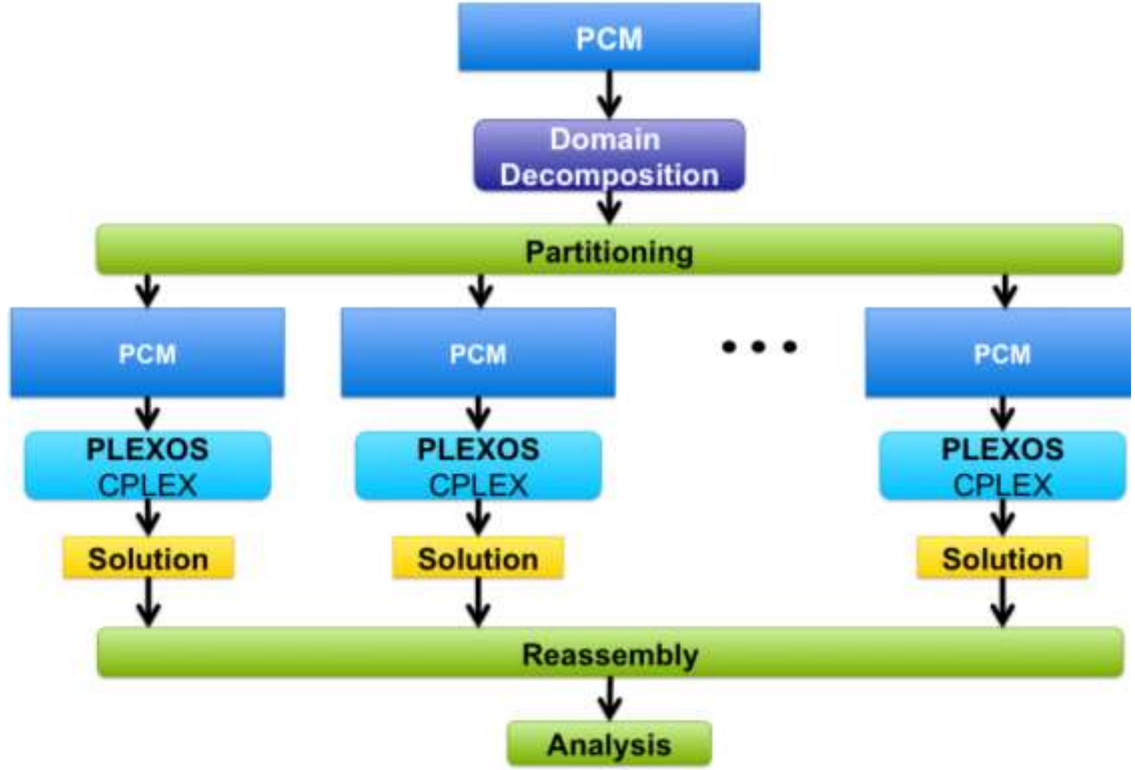
12 parallel ERGIS simulation take roughly a week to compute.
(limited by processors and memory on windows desktop)

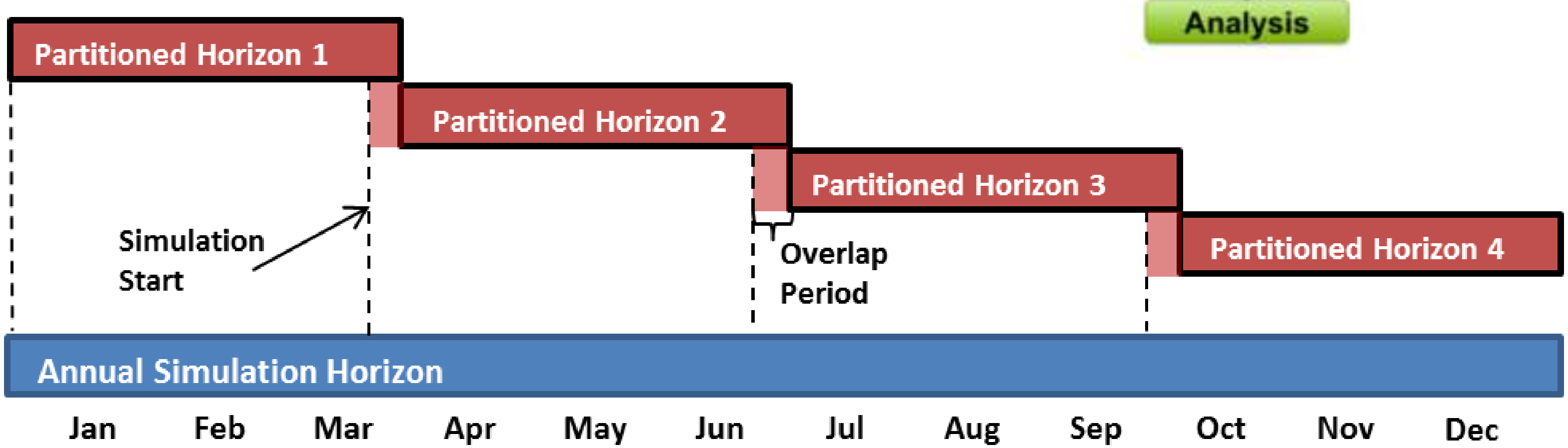
UC on NREL's HPC

NREL PIX 24580

Peregrine Characteristics:

- 11520 Intel Xeon E5-2670 "SandyBridge" cores
- 14400 next-generation Intel Xeon "Ivy Bridge" core
- 576 Intel Phi Intel Many Integrated Core (MIC) core co-processors with 60+ cores each
- 32 GB DDR3 1600Mhz memory per node
- Peregrine will deliver a peak performance of 1 petaFLOPS



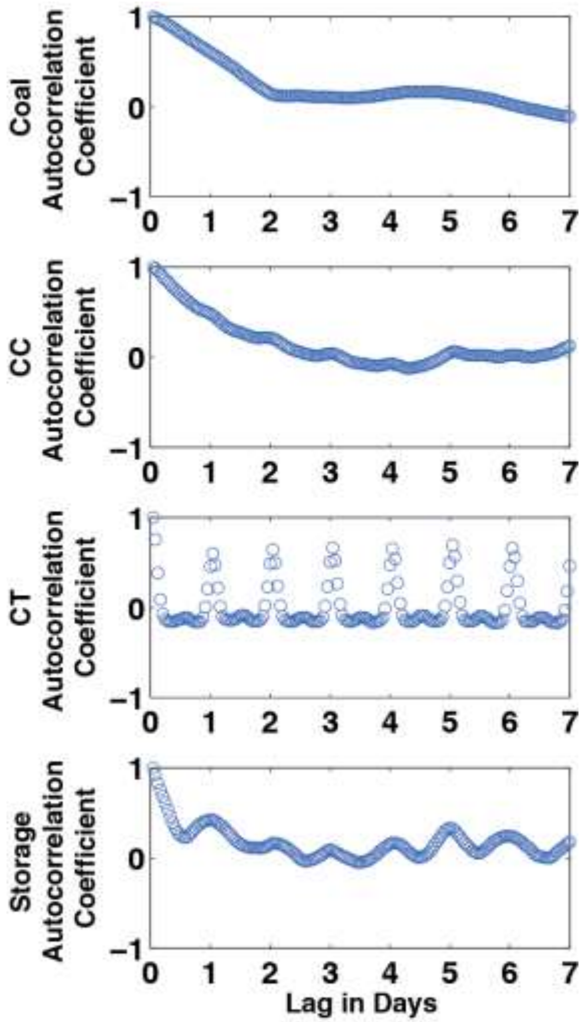


Idea: Parallelize in the Time Domain

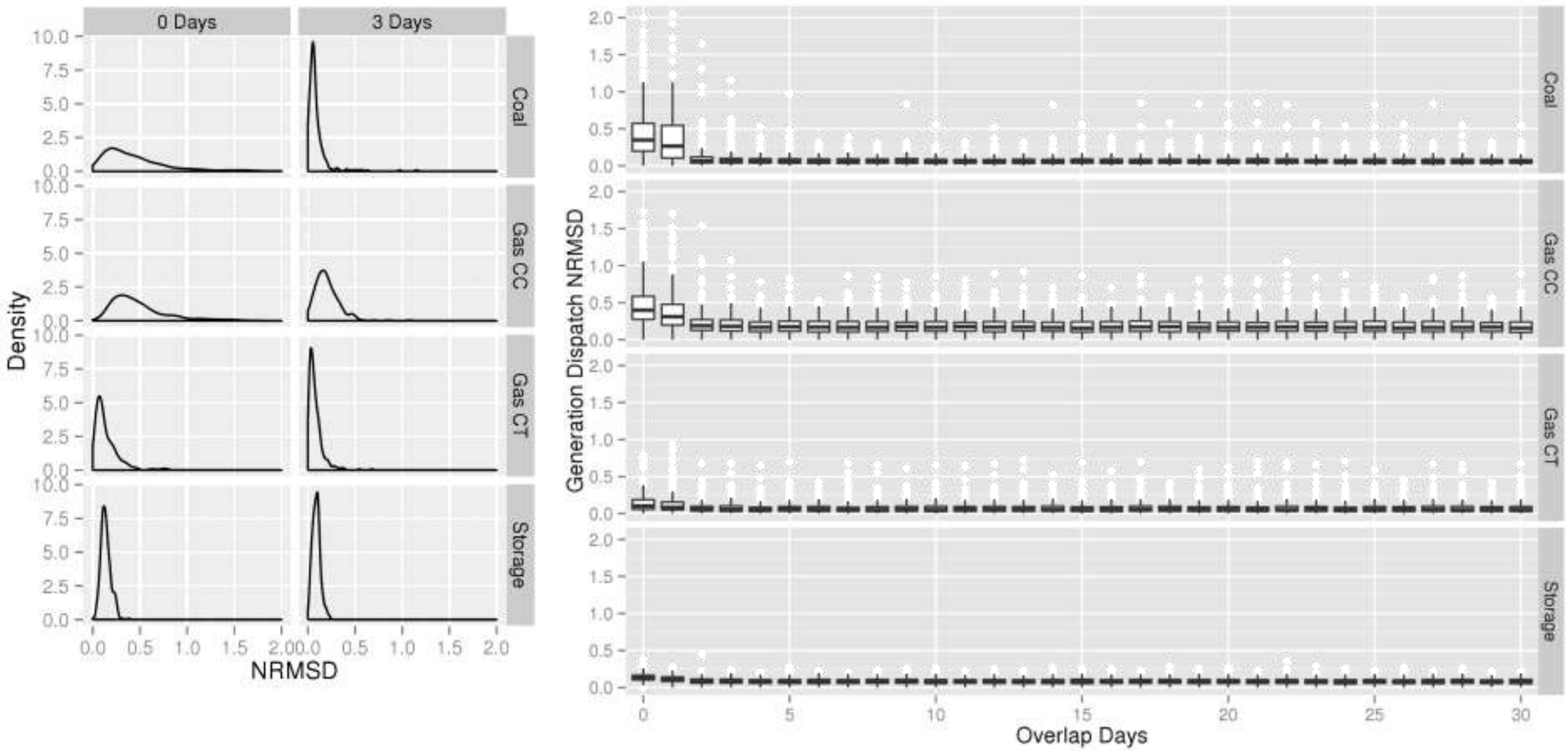
Hypothesis: a decision at time *t* is not dependent on the state of the system at previous time intervals, given a delay of *n* time periods.

Plotted here: Autocorrelation of the generator unit commitment decision variable for a group of generators.

The duration of the lag necessary for the autocorrelation of the Unit Commitment to reach a local minimum is called the Unit Commitment Decision Persistence, or just **Persistence**

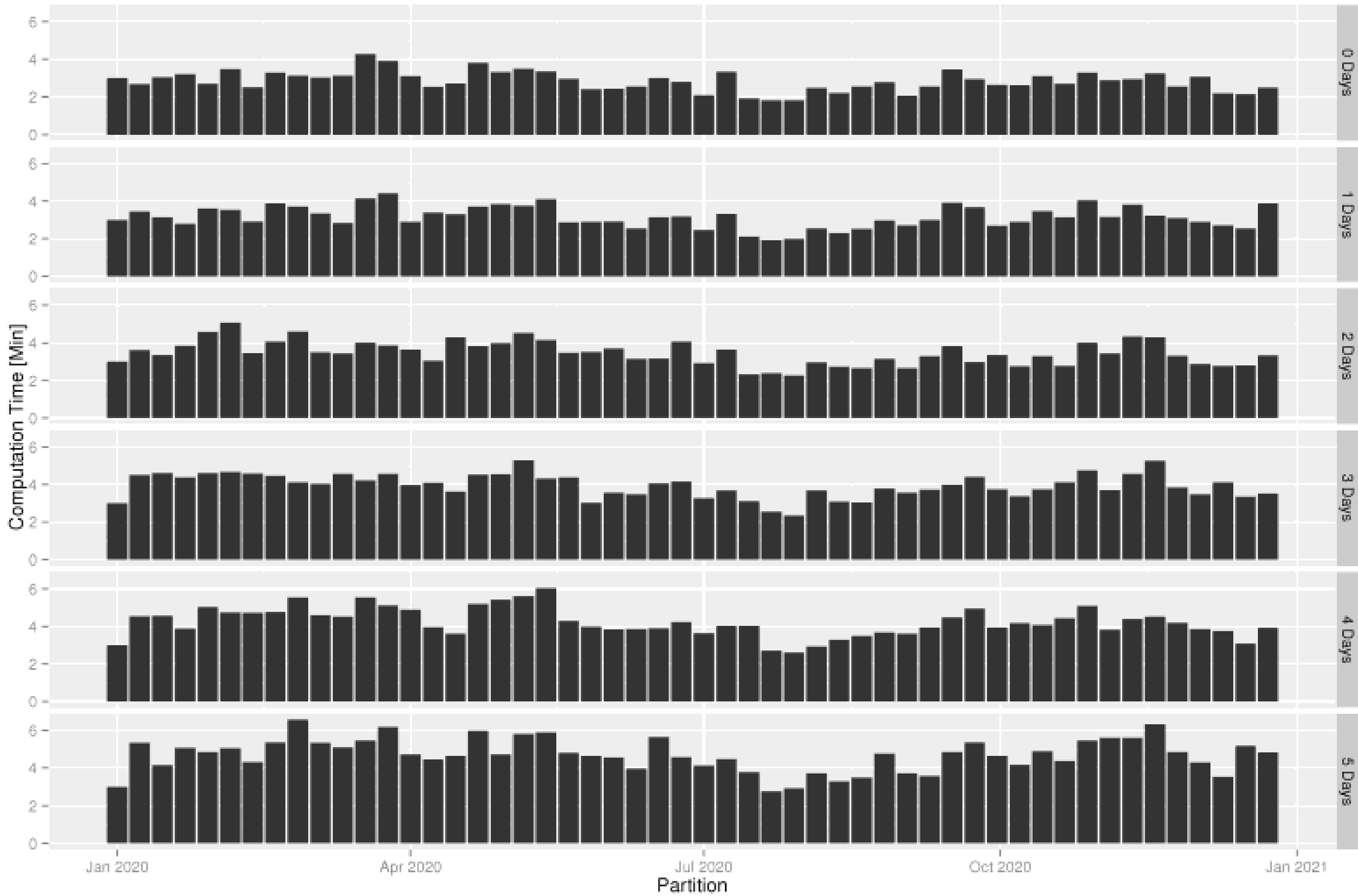


Effect of Overlap on Dispatch



Normalized root mean square difference (NRMSD) in generation dispatch, by type of generator, relative to the annual solution. This calculation is made each day and plotted relative to the number of overlap days (number of days since the start of the optimization).

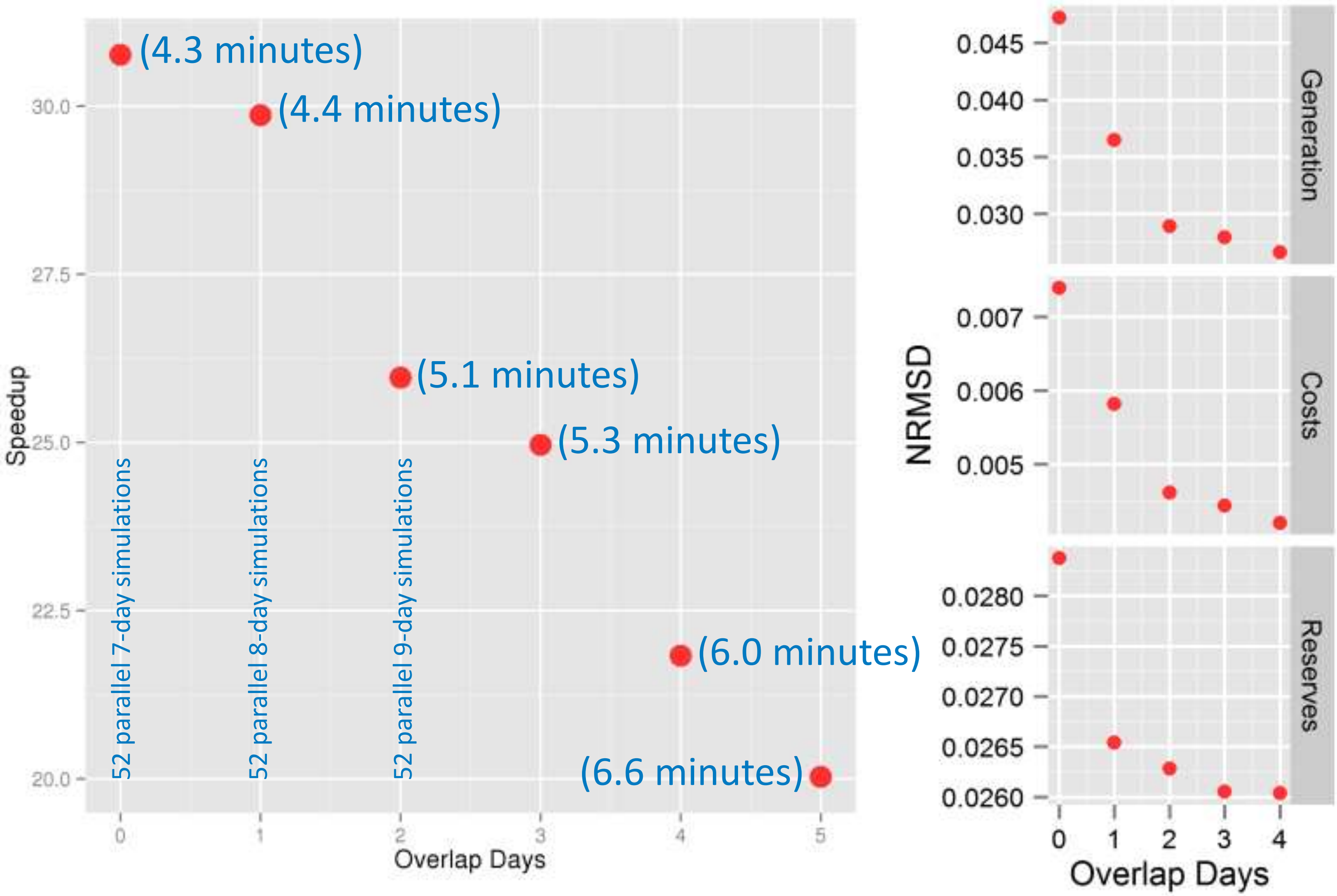
ST Solution Time



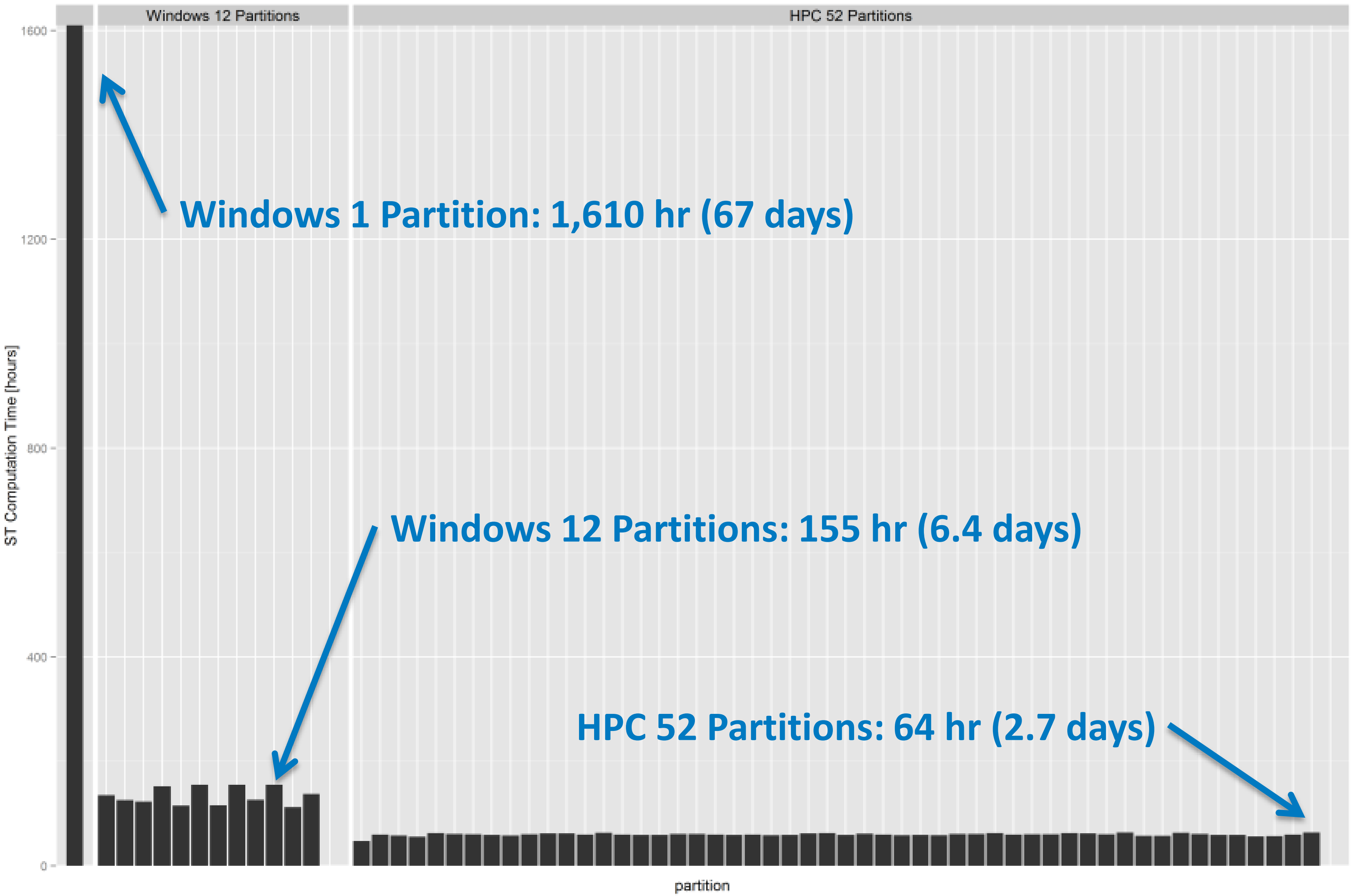
9-day simulations: weekly with 2-days of overlap.

Speedup in Hourly UC Simulation (RMPP)

Annual solution takes 131.7 minutes.
With 52 partitions (with increasing overlap days):

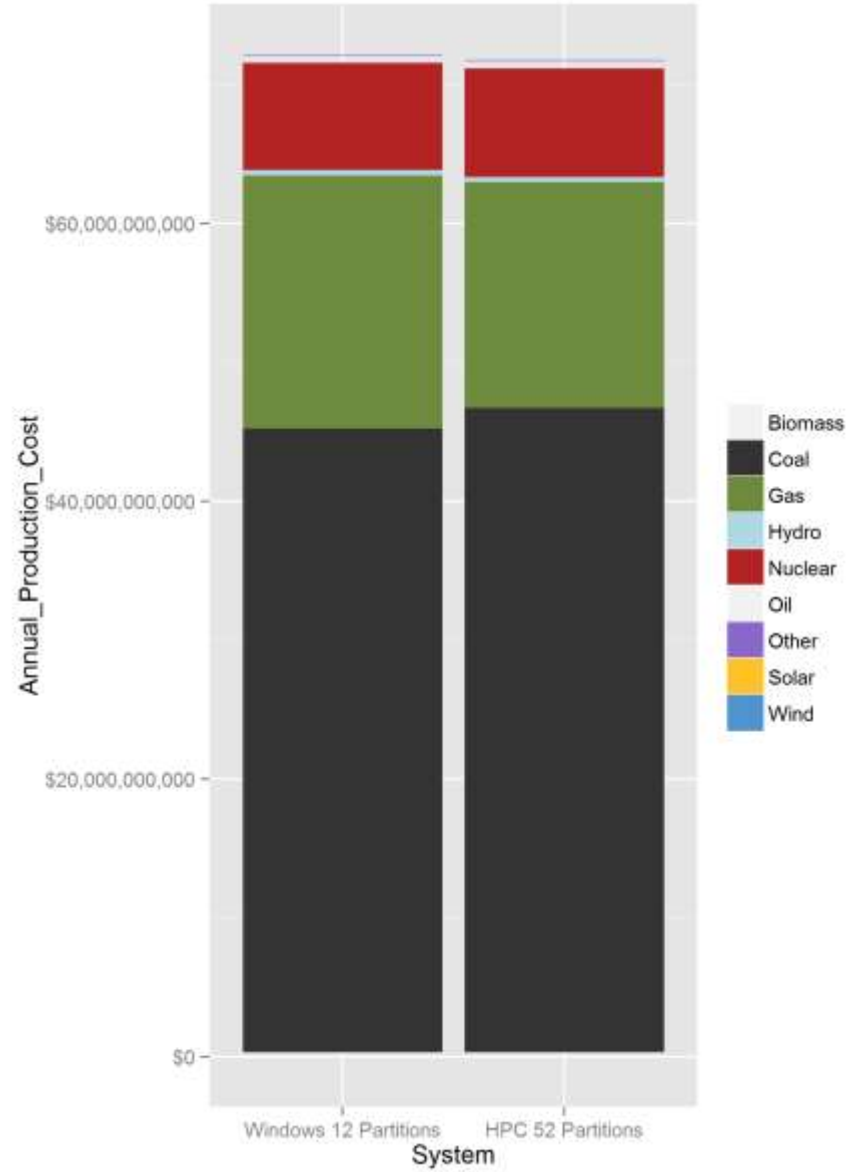


ERGIS Simulation Time Comparison

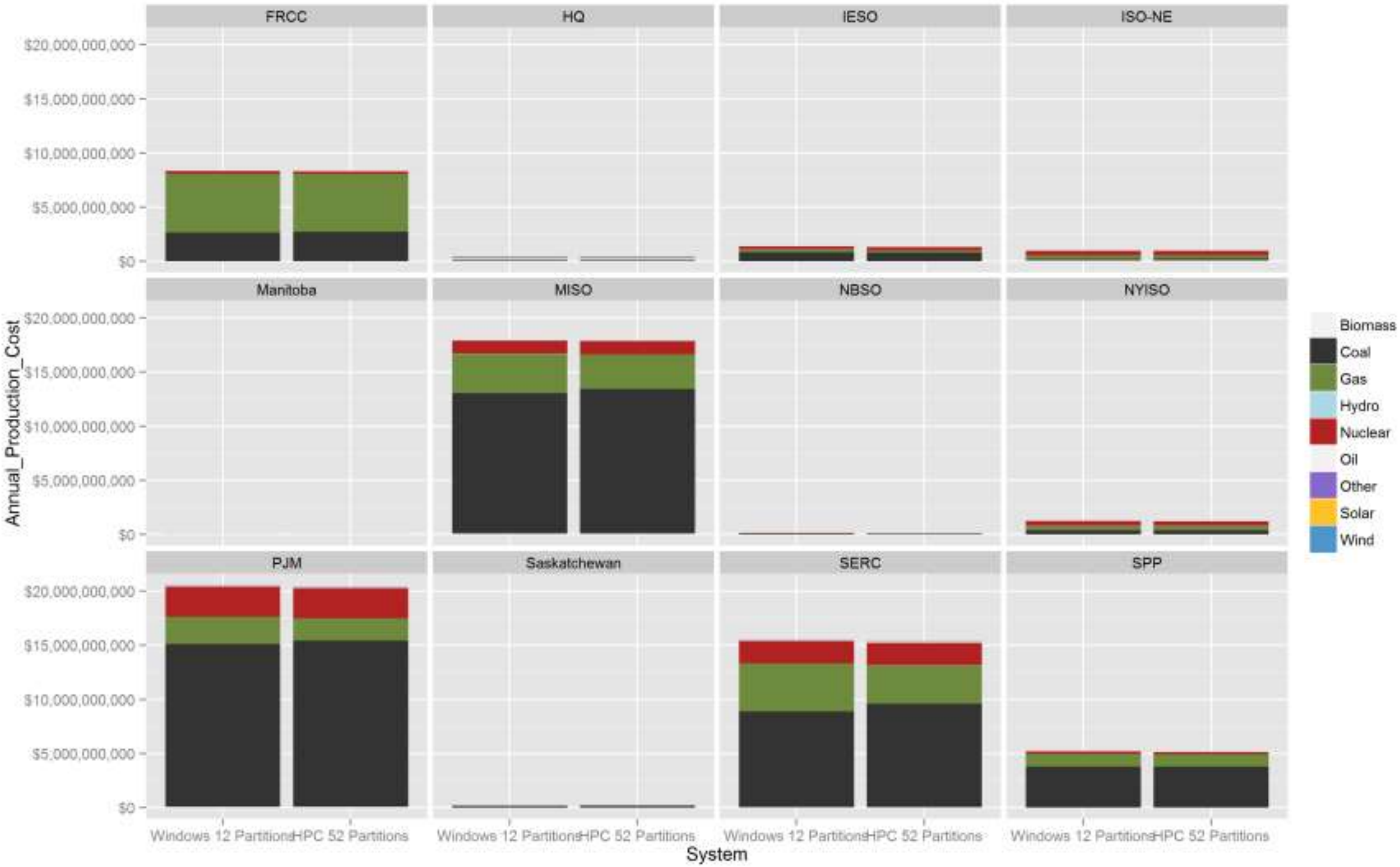


Annual Production Cost

- **Windows solution:**
  - 12 partitions
  - No overlap
- **HPC solution:**
  - 52 partitions
  - 2 days overlap
- **Total difference: 0.57%**

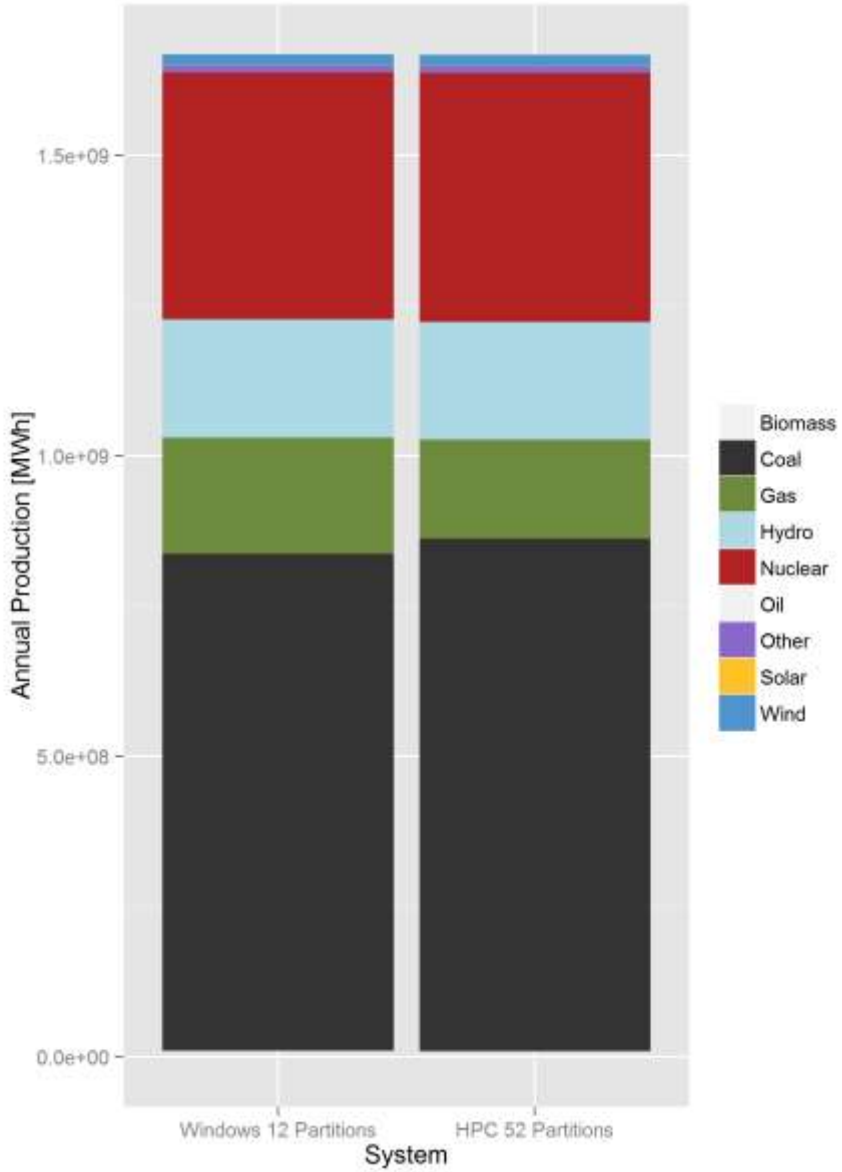


Annual Production Cost

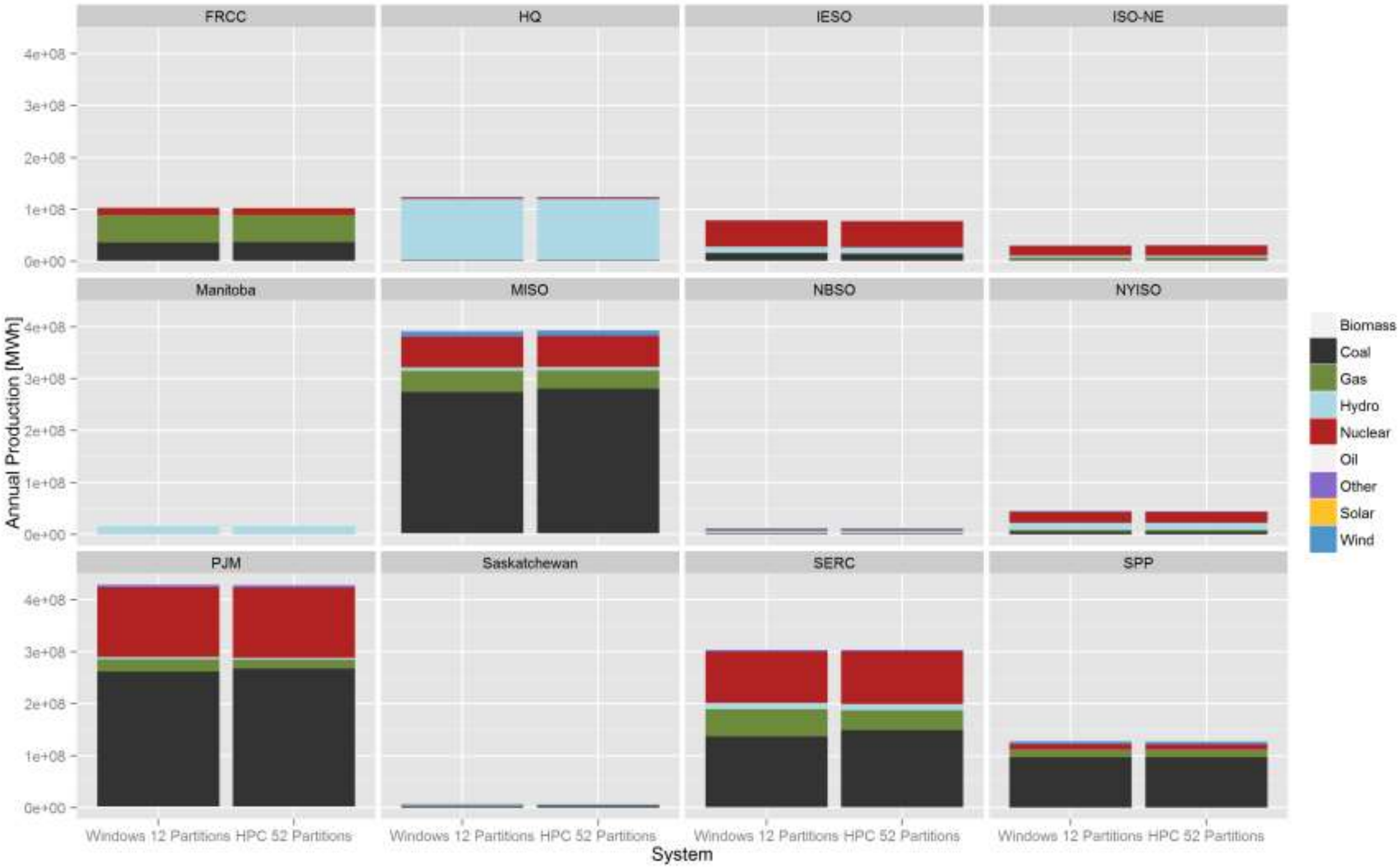


Annual Generation

- **Windows solution:**
  - 12 partitions
  - No overlap
- **HPC solution:**
  - 52 partitions
  - 2 days overlap
- **Total difference:**
  - 0.07%
    - attributed to numerical precision in aggregation



Annual Generation



ERGIS HPC Conclusions

- **Success!**
  - Speedup and solution quality
- **Challenges:**
  - Windows/Linux compatibility
  - Compilation times
  - Licensing

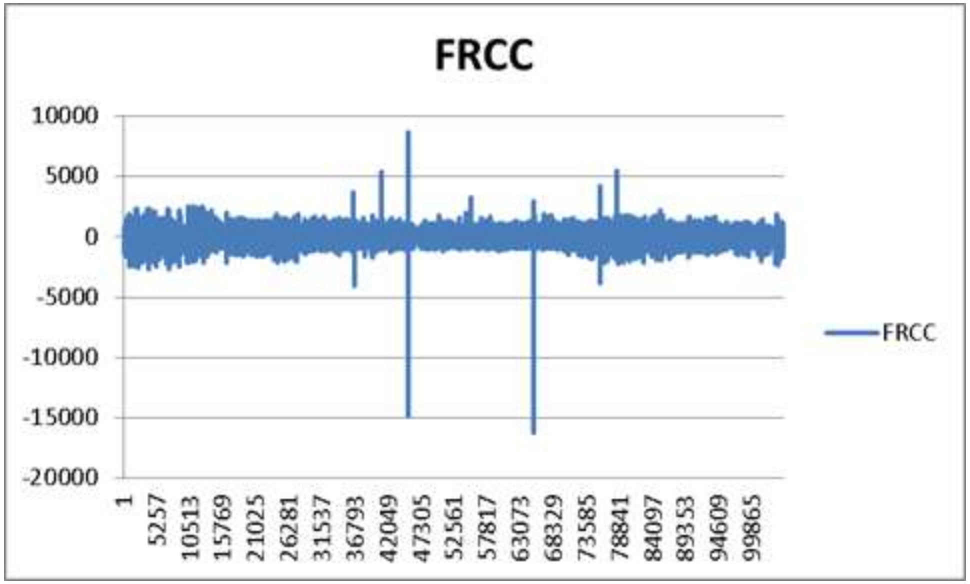
HPC Tour and Lunch

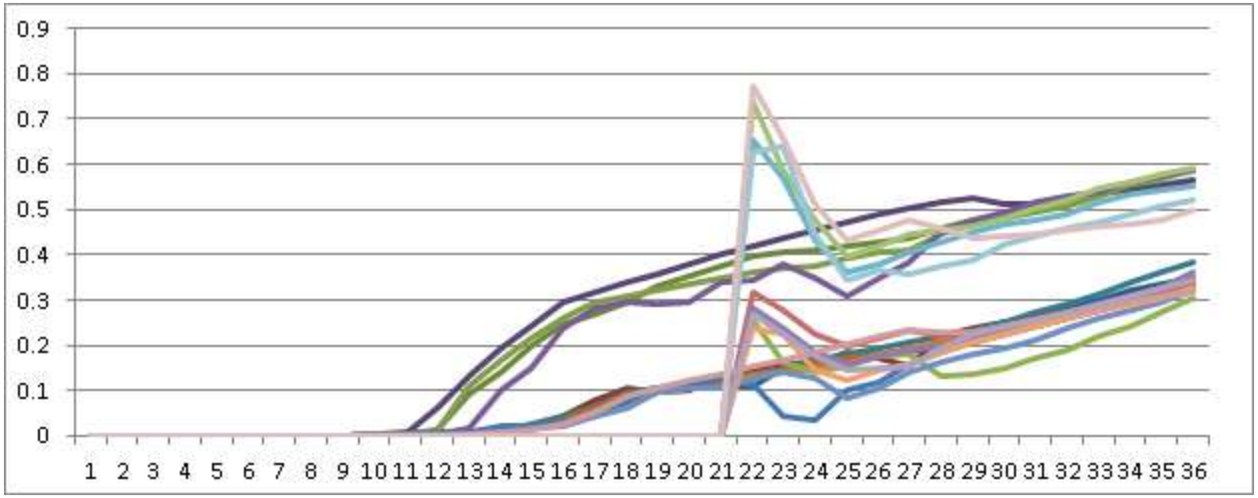
Solar Data Review

ERGIS Solar Data Update

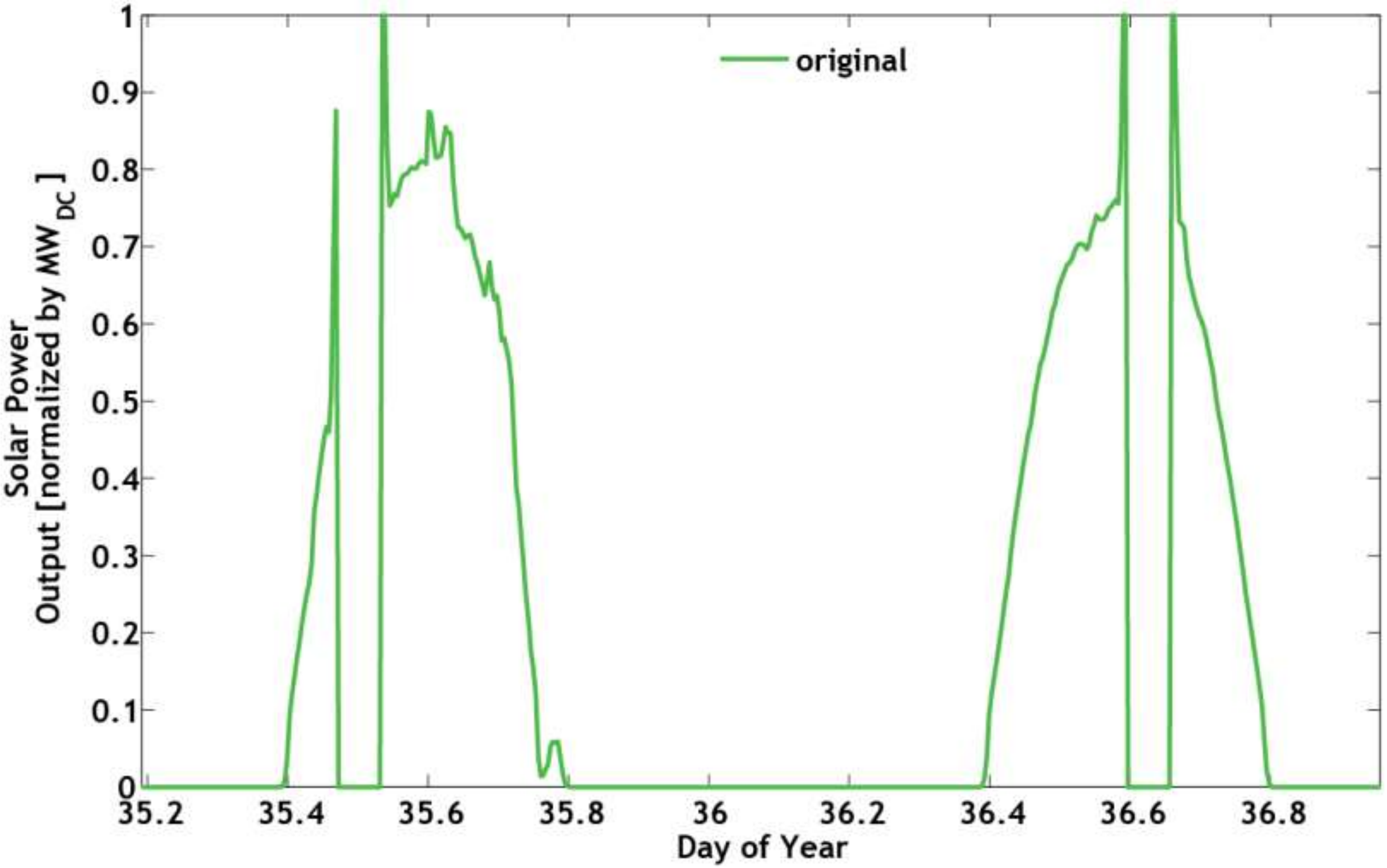
- **Sub-hour solar power data**
- **Solar forecast data:**
  - Day-ahead
  - 4-hours-ahead
- **Next steps:**
  - Making solar data available to the public
  - Correcting real time and forecast datasets
  - Incorporating solar data into reserves calculation

5-minute Errors

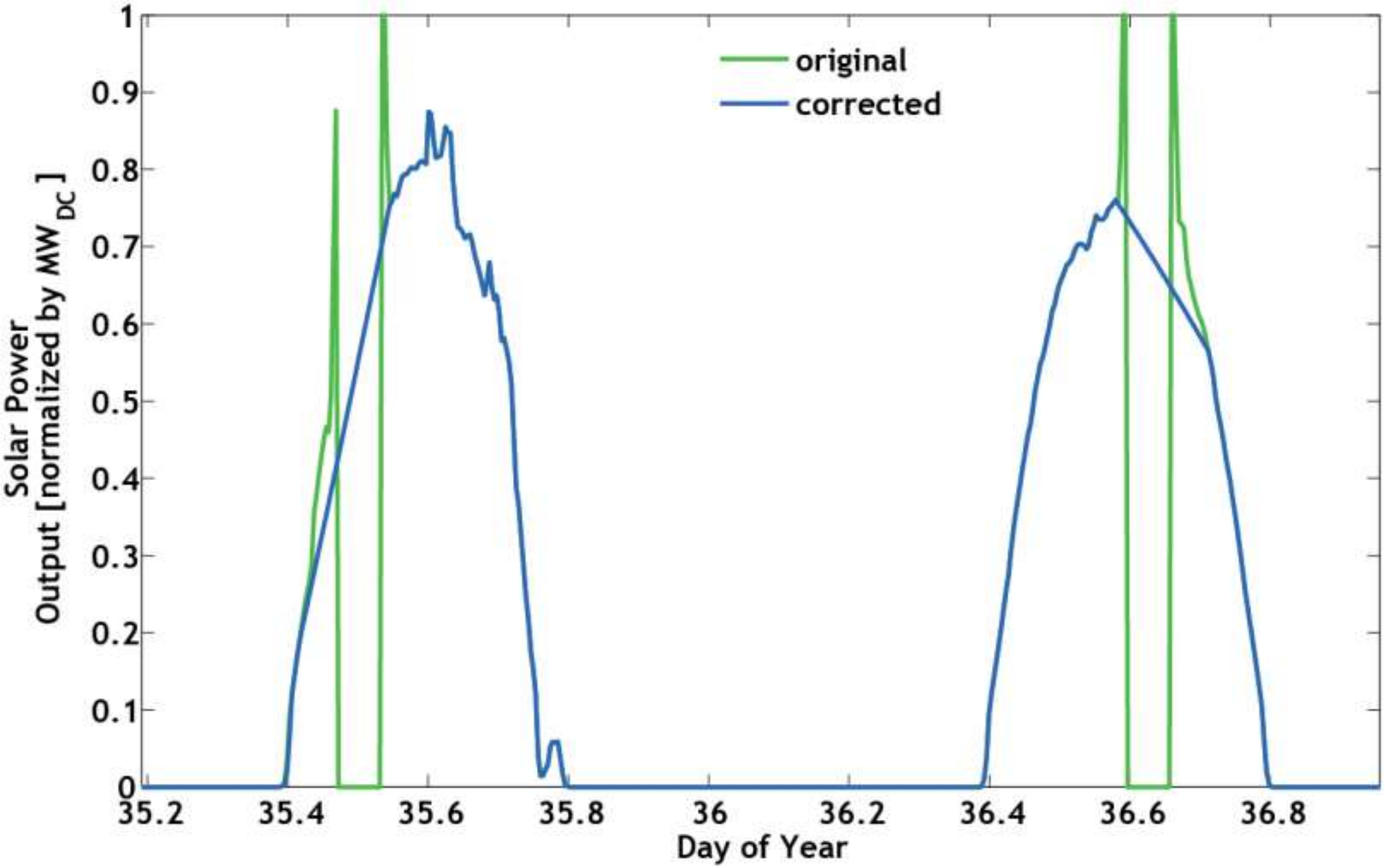




Problem with Sub-hour Clear Sky Data

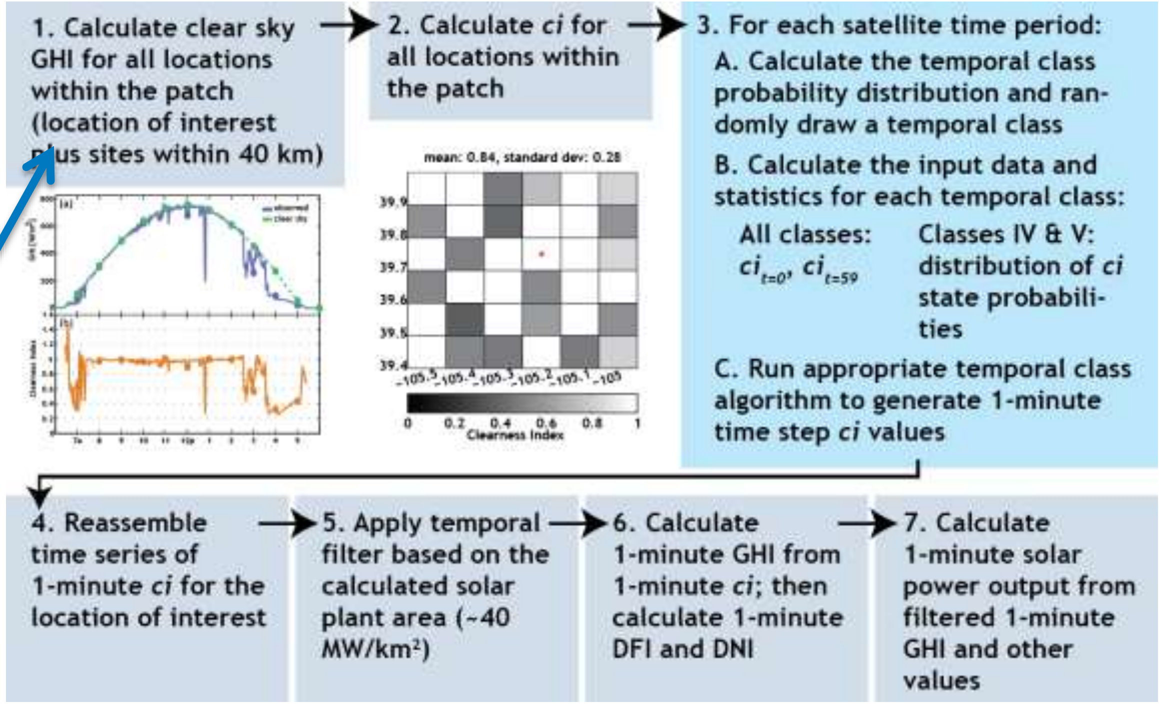


Problem with Sub-hour Clear Sky Data



Correction to Missing Satellite Data

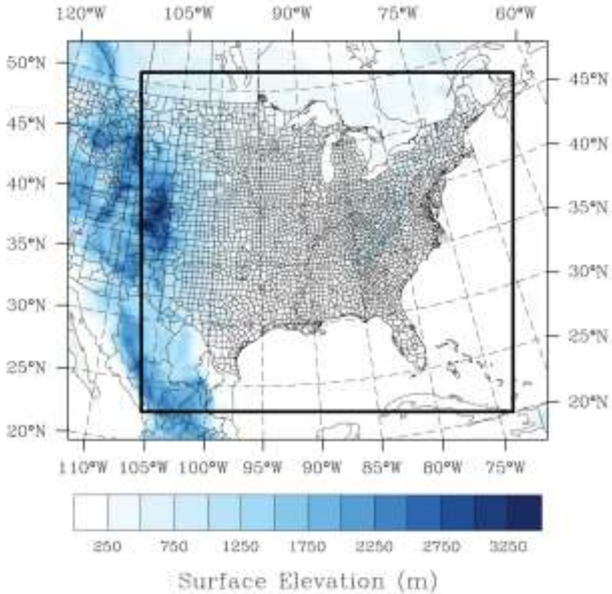
Day of Year	Missing Hours			
36	11	12	13	
37	15	16	17	
120	11	12		
158	8	9		
175	13	14		
177	21			
179	9	10	11	
182	12	13	14	15
192	19			
227	8			
360	17	18		



Correct clear sky algorithm by replacing missing hours with average clear sky value.

Solar Forecast Data

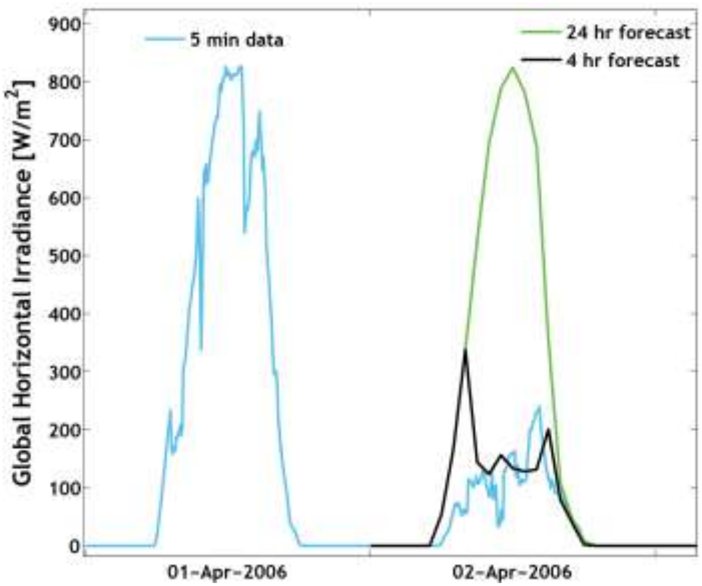
- **Day-ahead**
  - WRF
  - Persistence
- **4-Hour-ahead**
  - WRF
  - Persistence



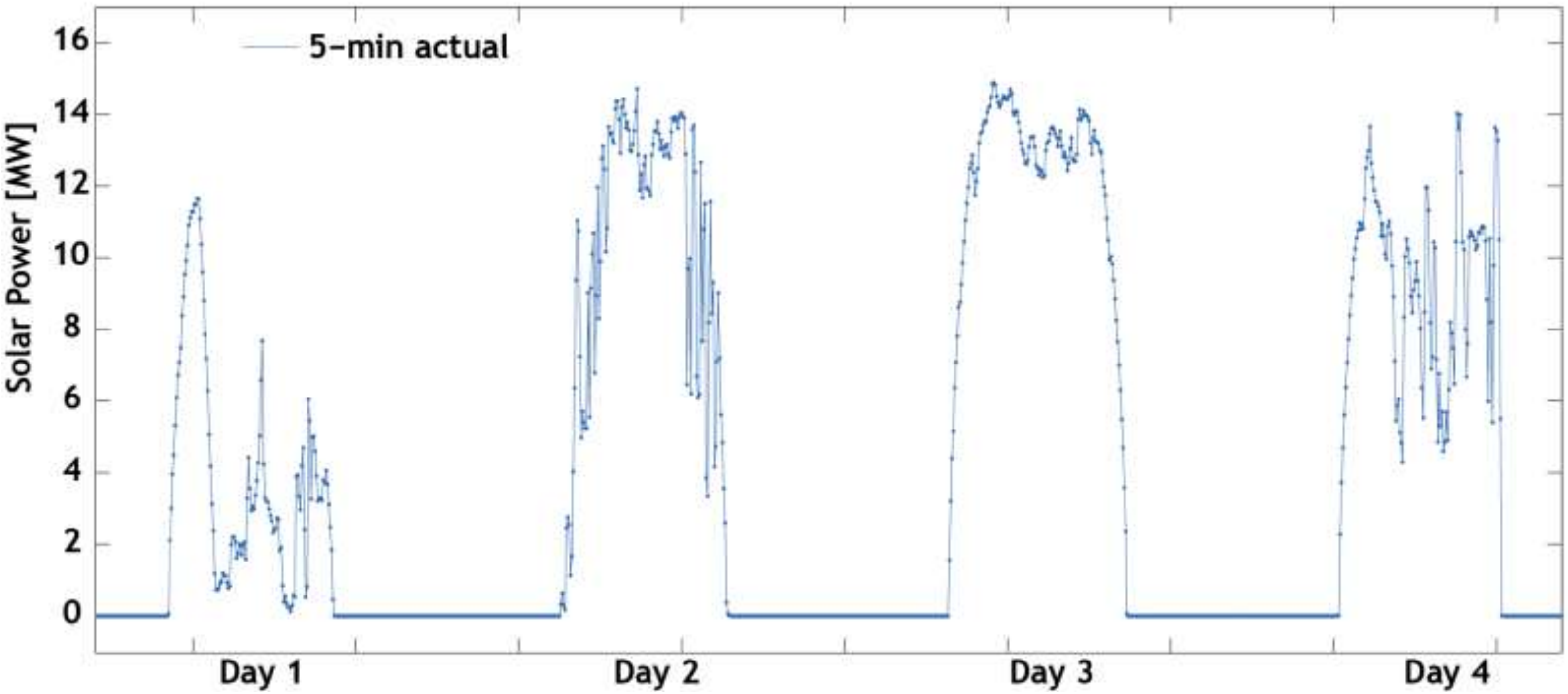
NREL's HPC resource: Peregrine (above)

NREL's WRF study area (left)

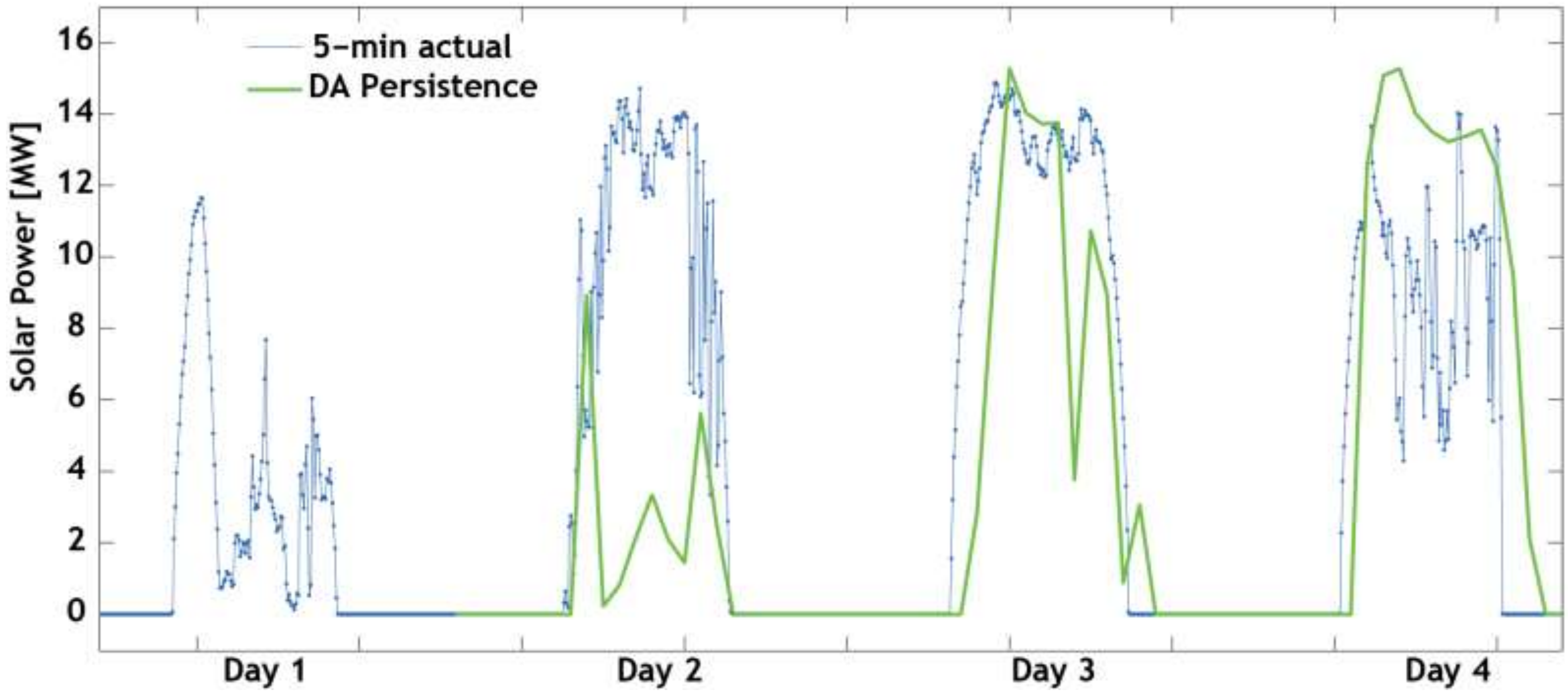
Persistence forecast (below)



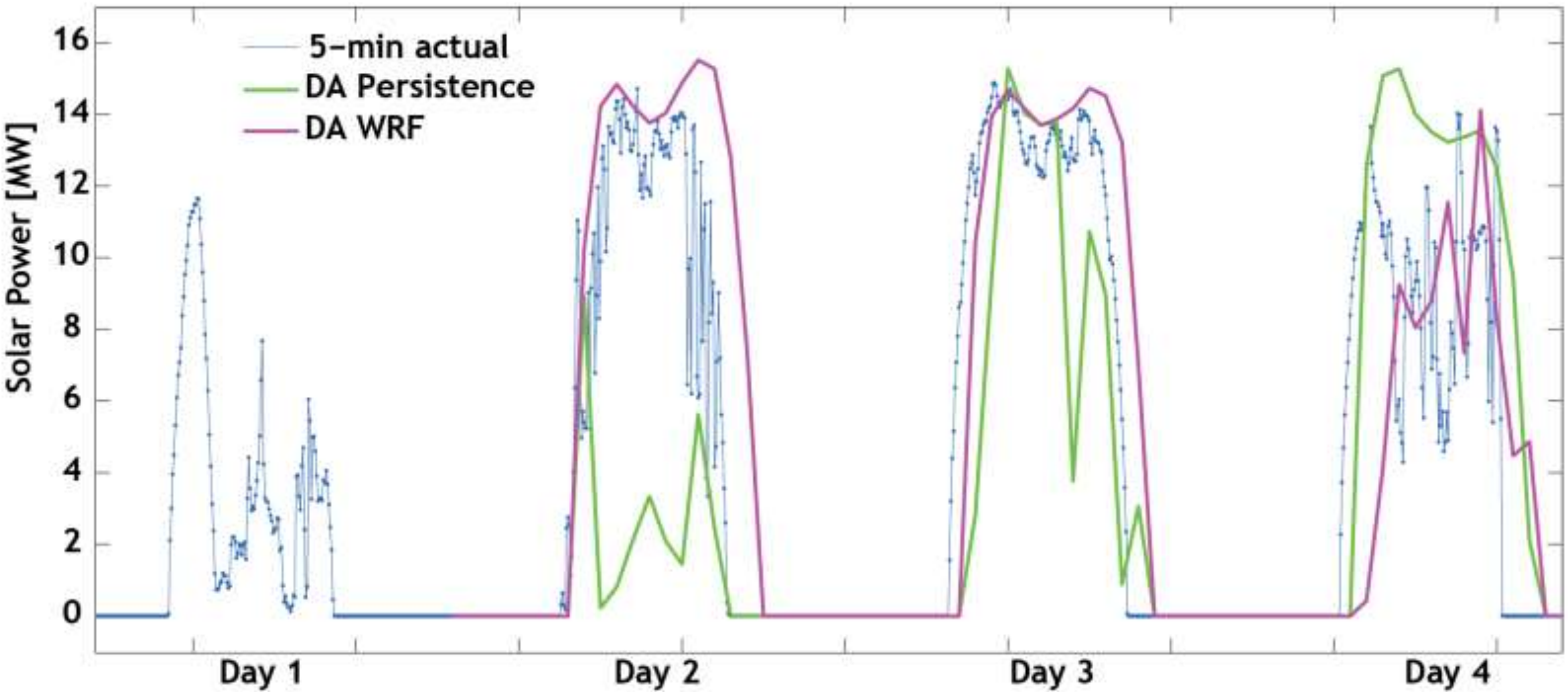
Day-Ahead Solar



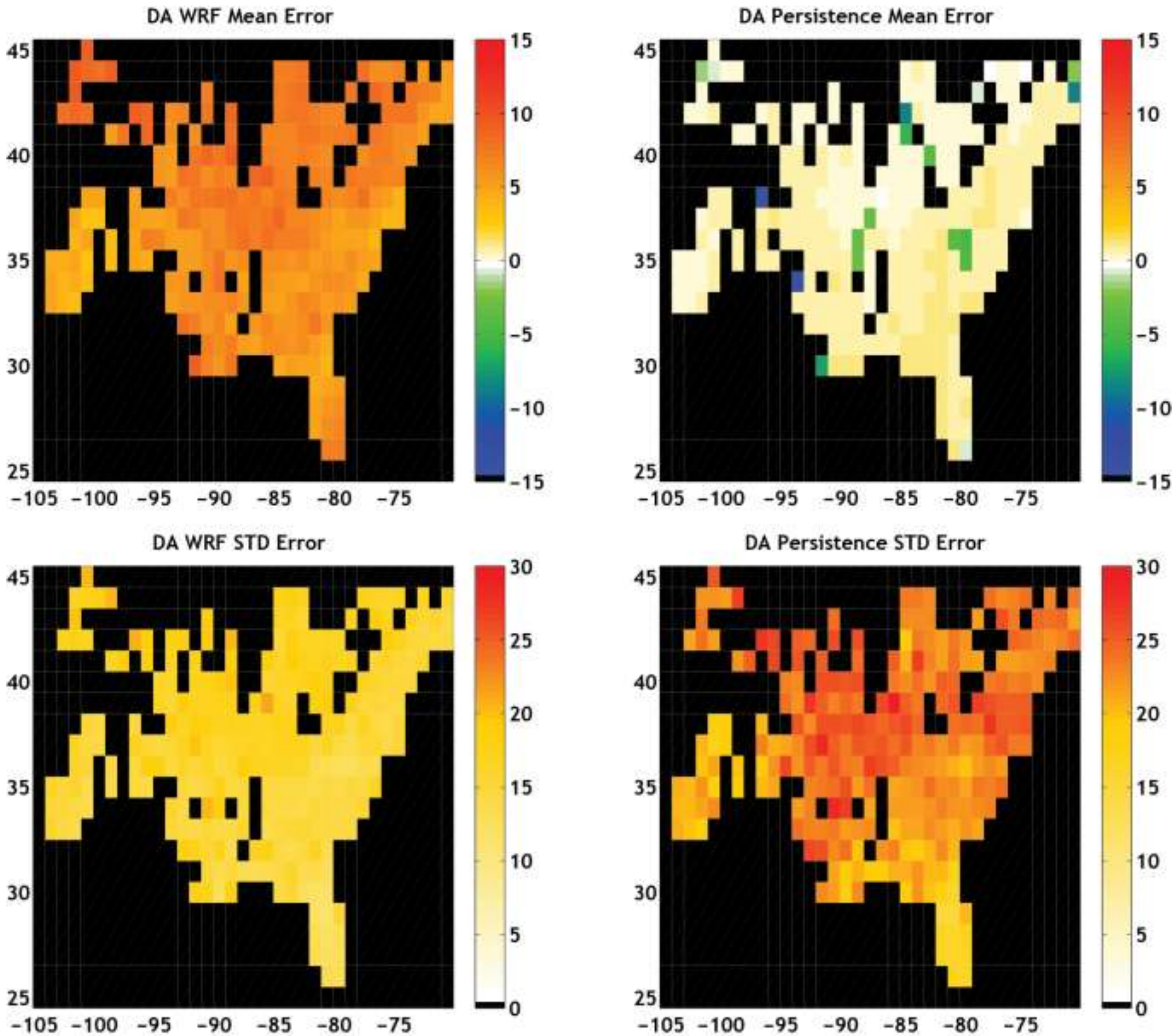
Day-Ahead Solar



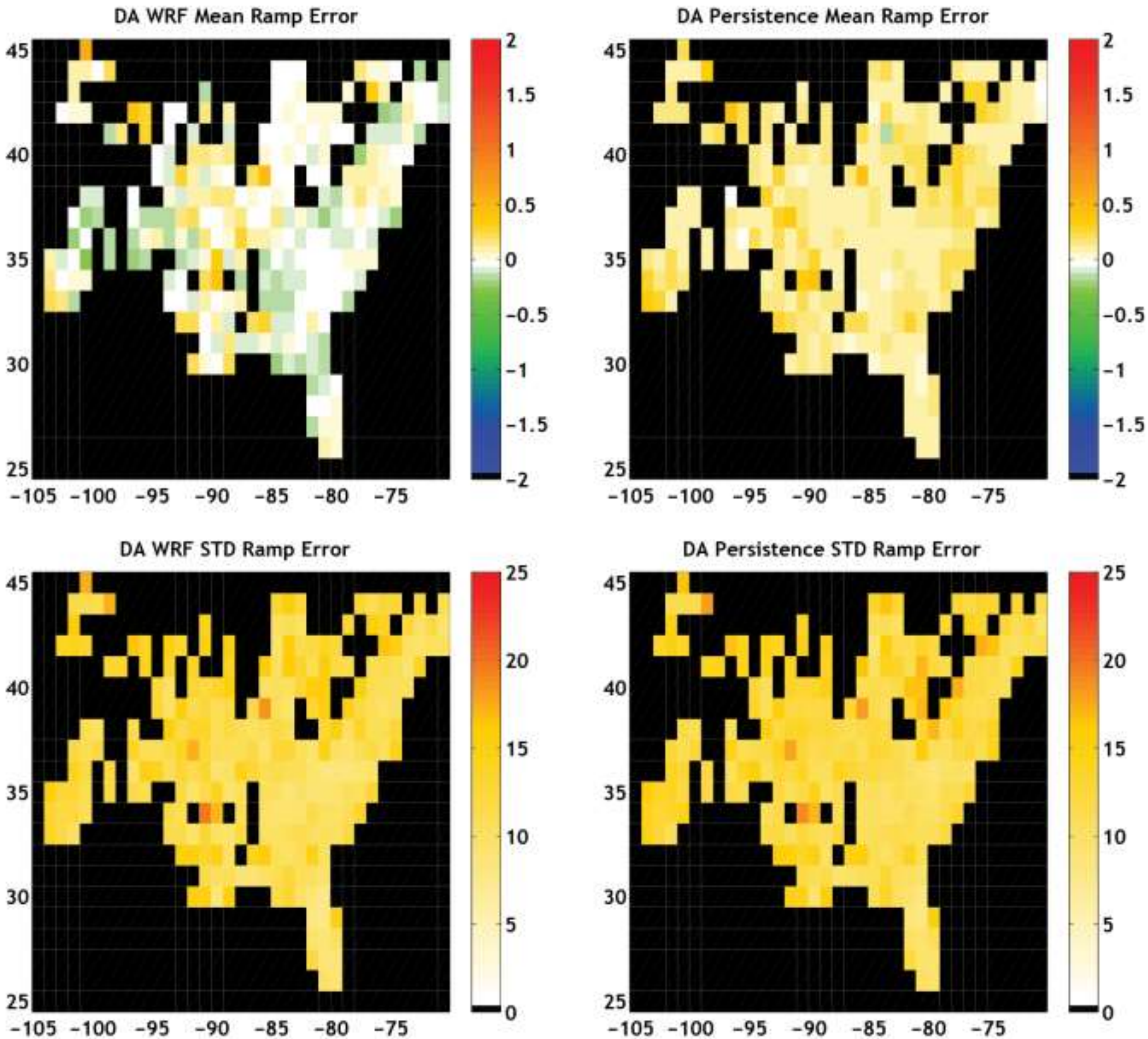
Day-ahead Solar



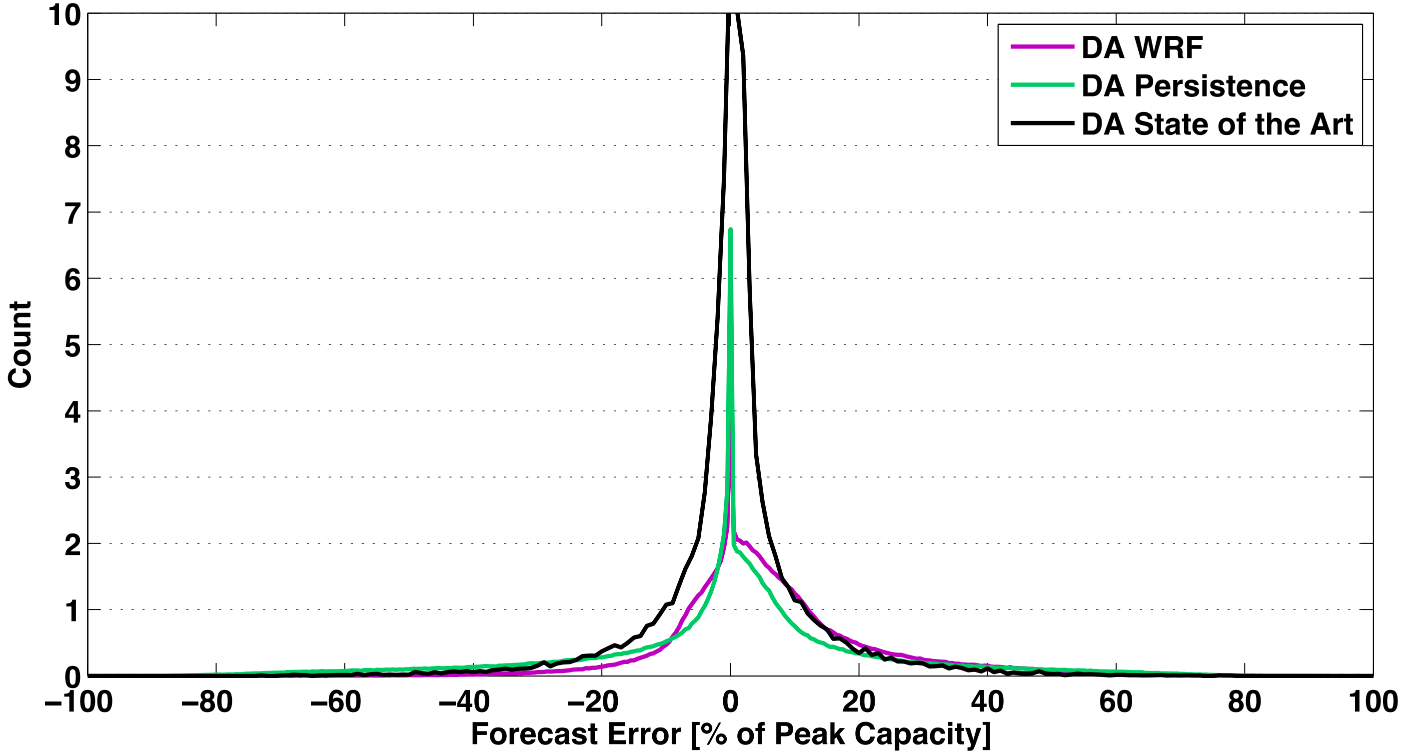
Day-Ahead Forecast Error



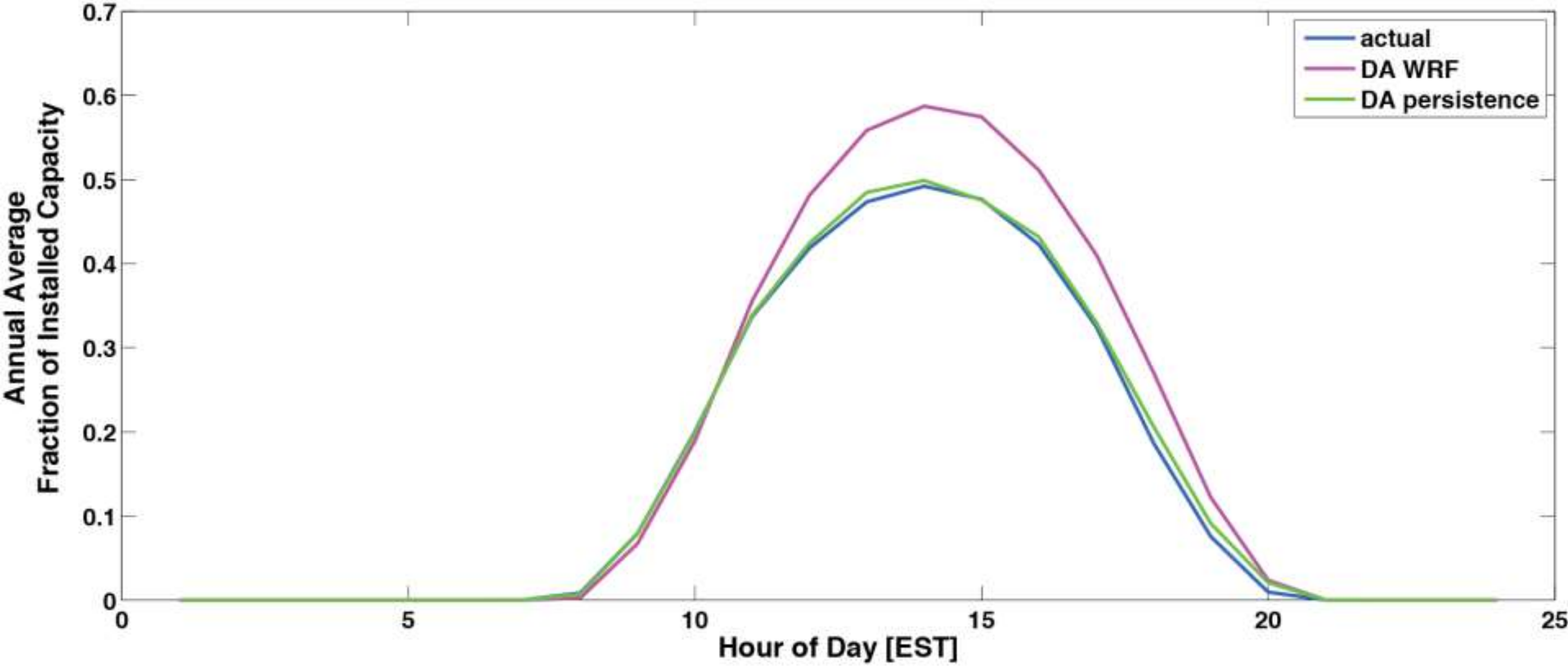
Day-Ahead Hourly Ramp Forecast Error



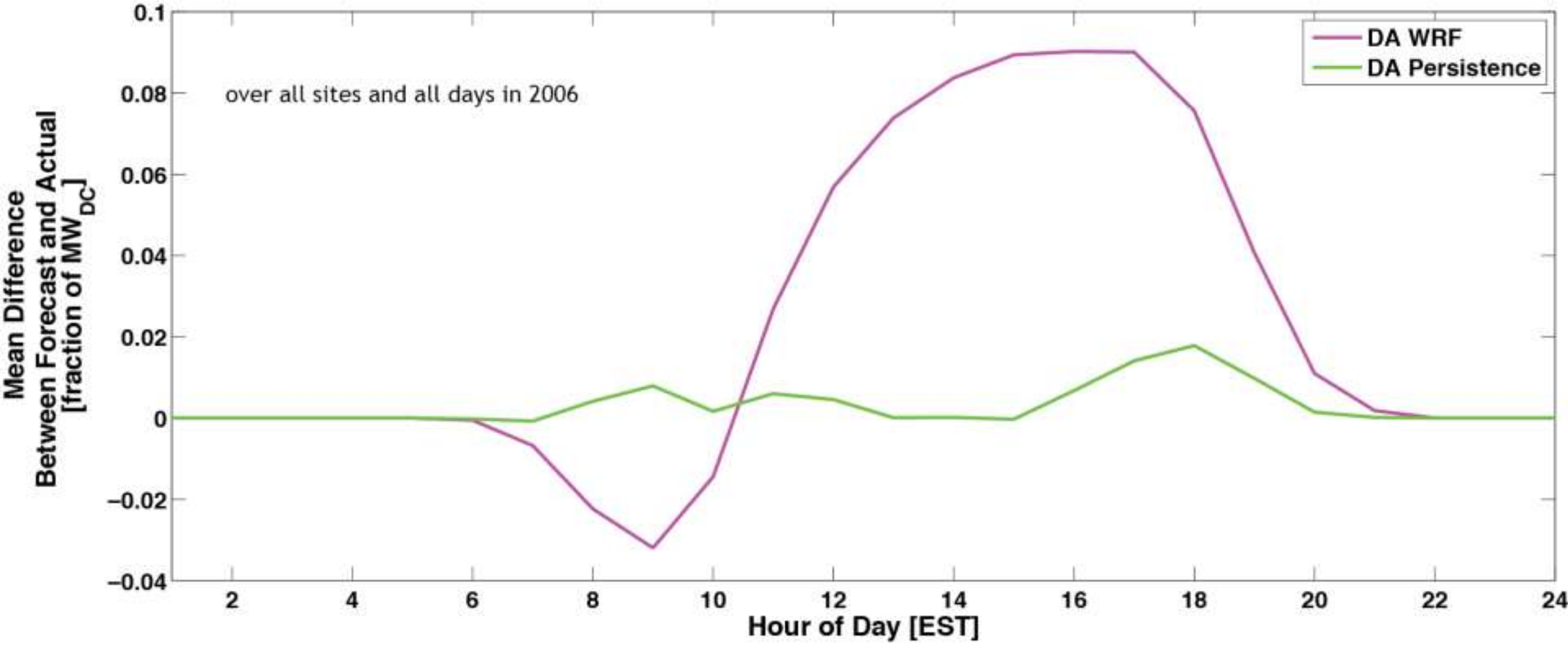
Day-Ahead Solar



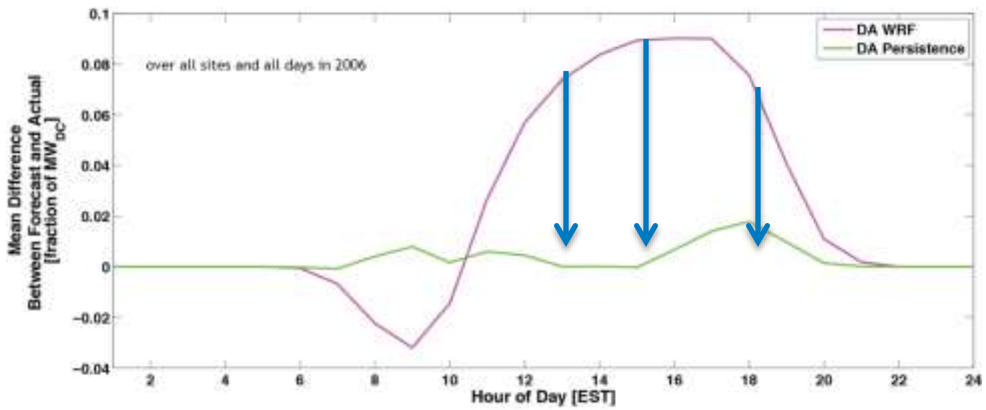
Bias in the WRF data



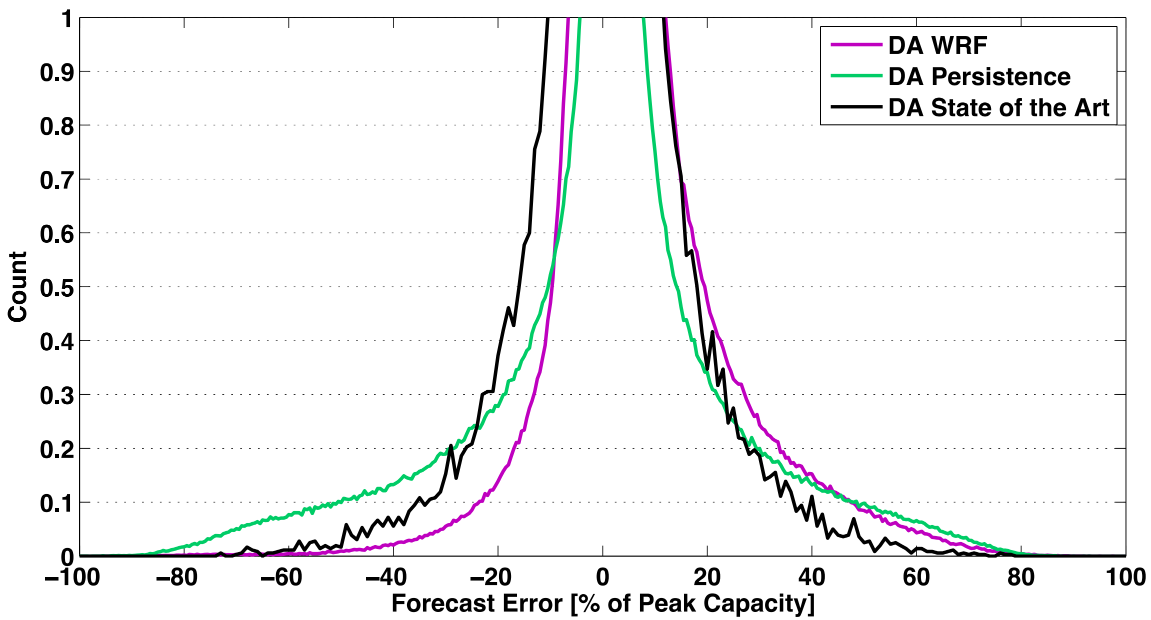
Bias in the WRF data



Correct Bias and Error Distribution



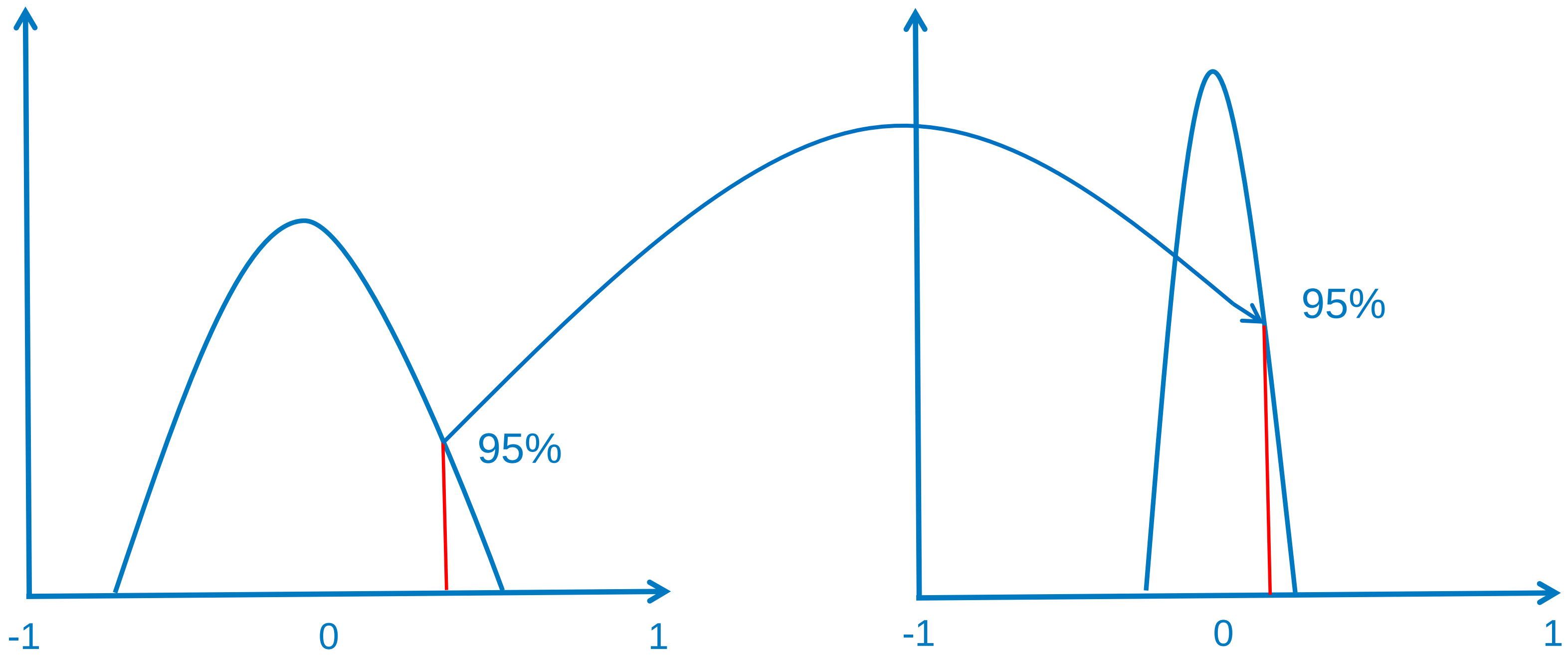
Adapt a technique developed by NREL to adjust wind forecast errors using "error distribution mapping" to solar forecasts.



Mapping Forecast Errors

WWSIS Forecast Errors

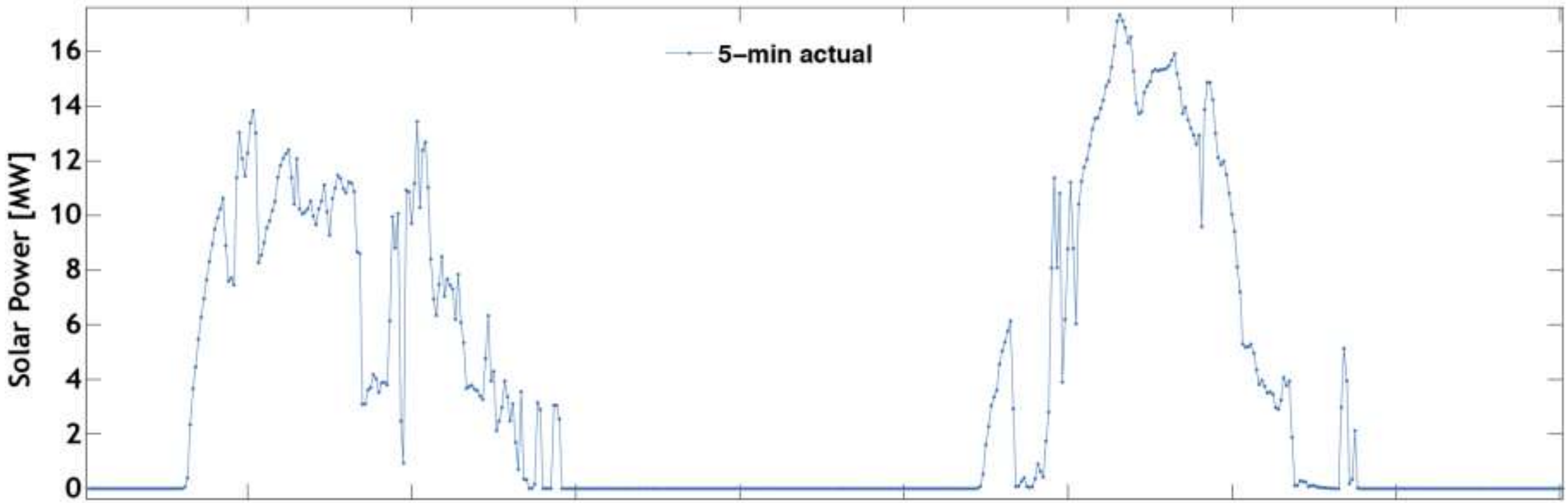
Model Production Forecast Errors



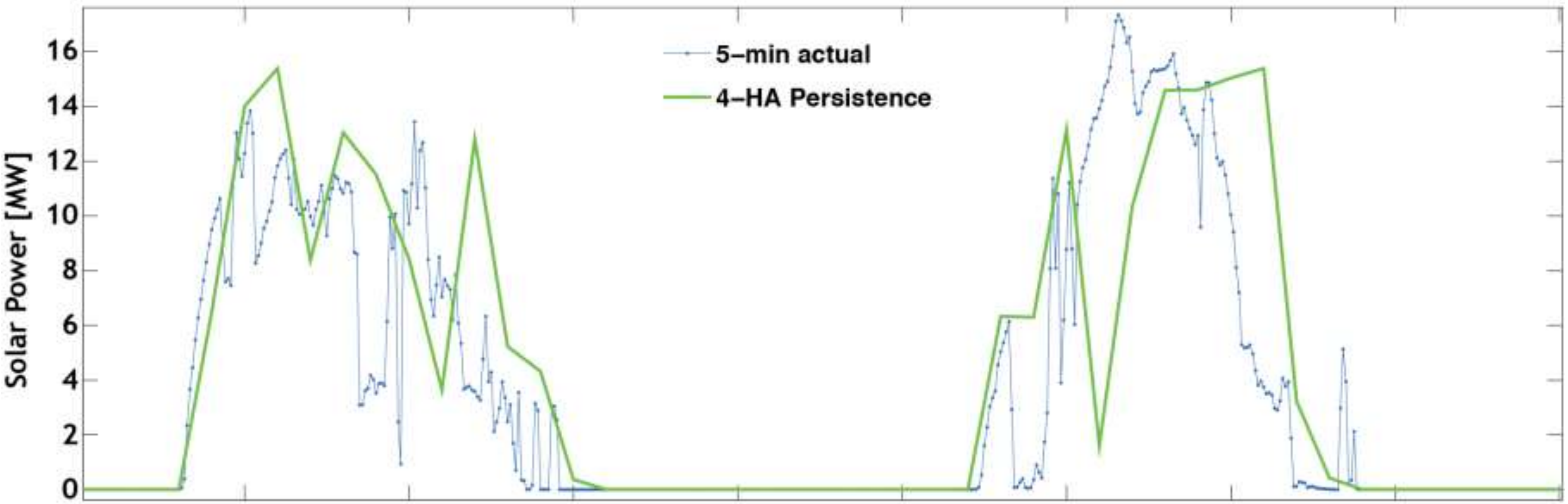
Normalized Forecast Error

Normalized Forecast Error

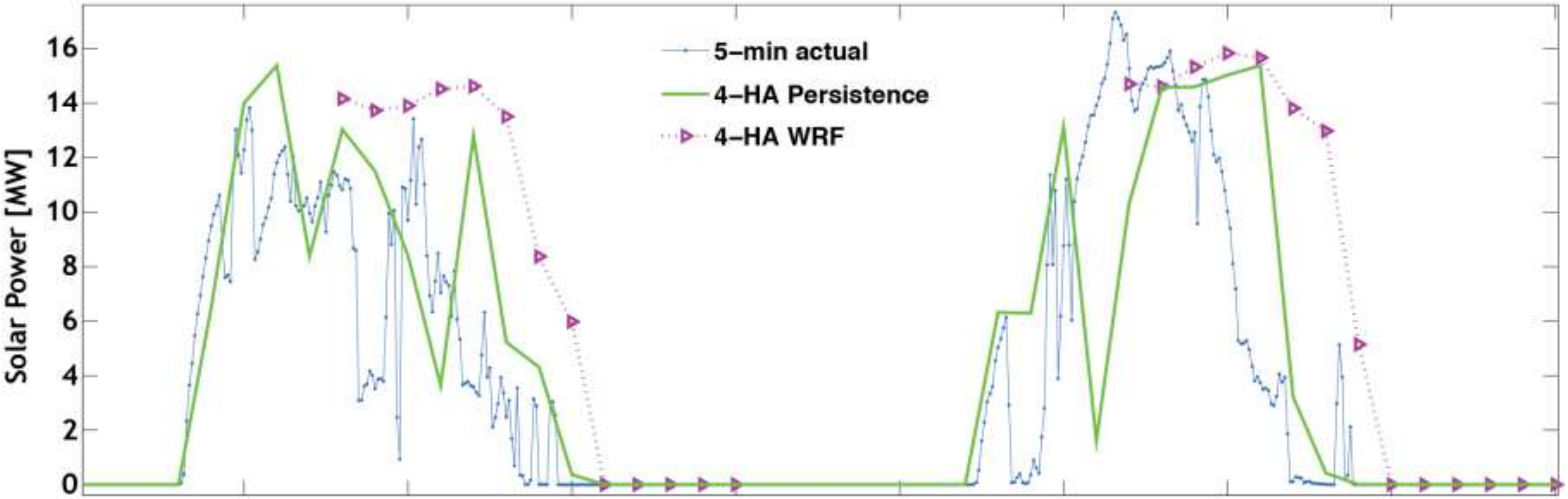
4-Hour-Ahead Solar



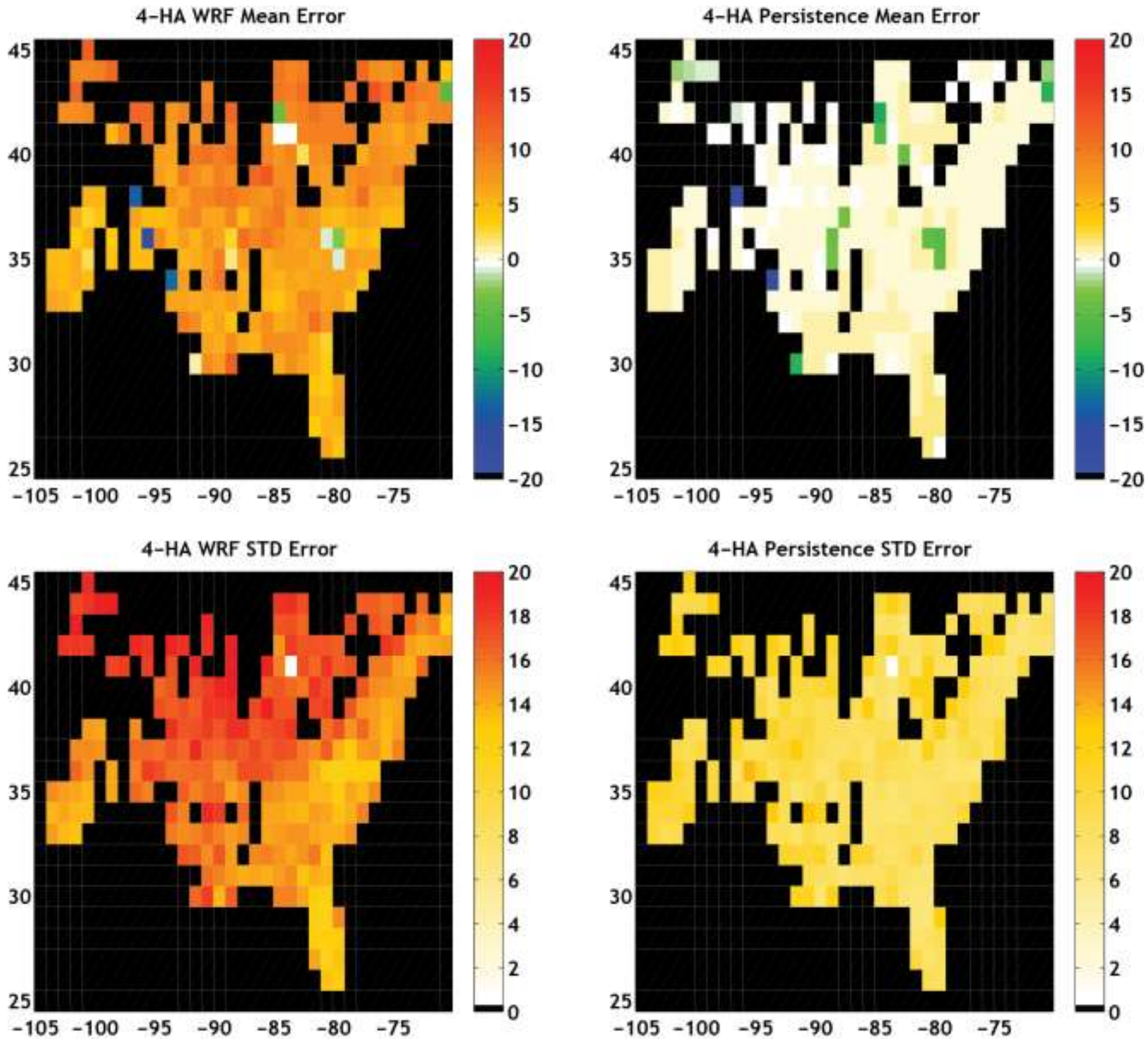
4-hour-ahead Solar



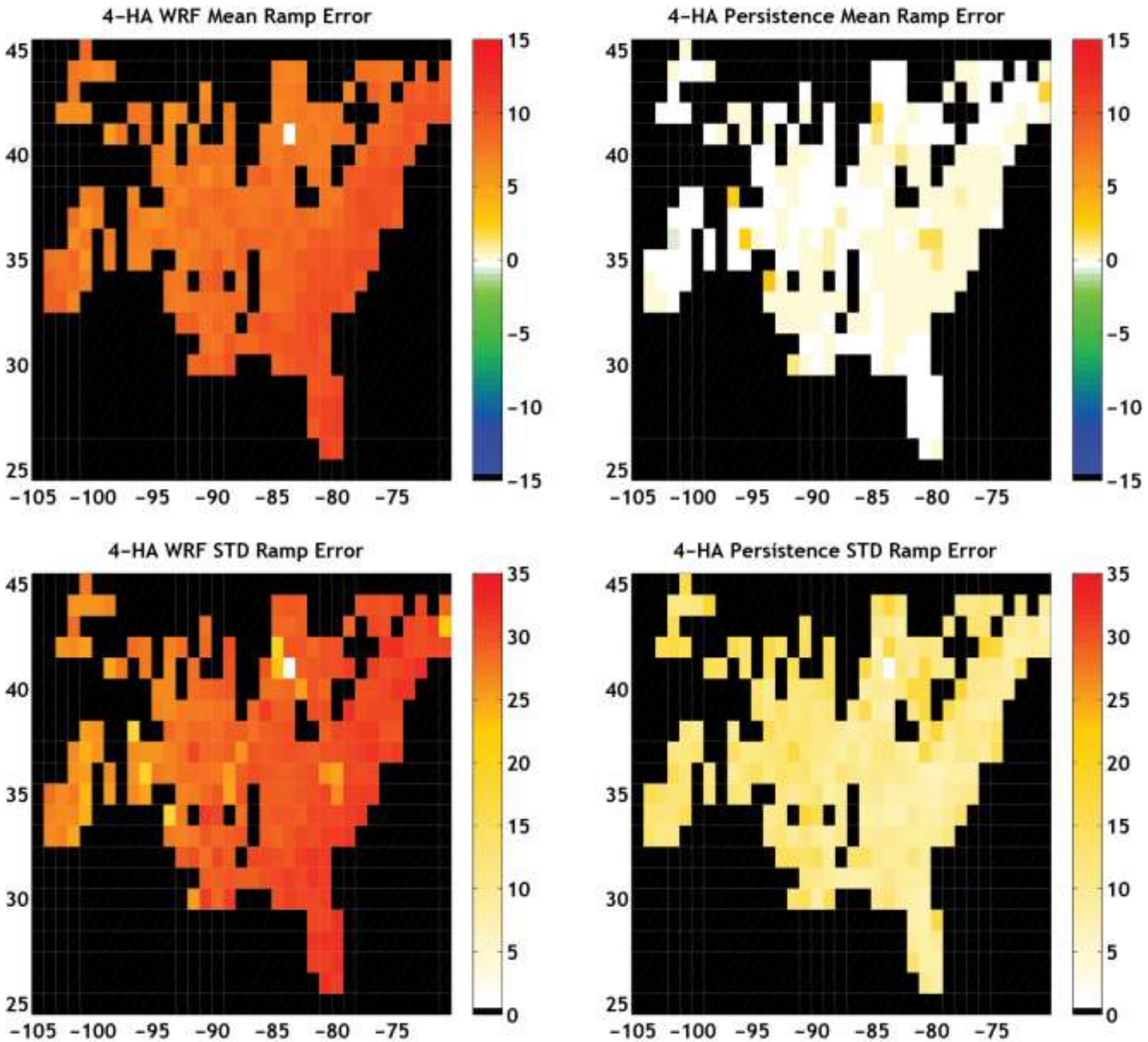
4-Hour-Ahead Solar



4-Hour-Ahead Forecast Error



4-Hour-Ahead Hourly Ramp Forecast Error



Next Steps

- Correcting real time and forecast datasets (end of February)
- Making solar data available to the public – including documentation on the sub-hour dataset and forecast datasets (end of March)
- Incorporating solar data into reserves calculation (March – April)

Net Load Analysis

Net Load Analysis

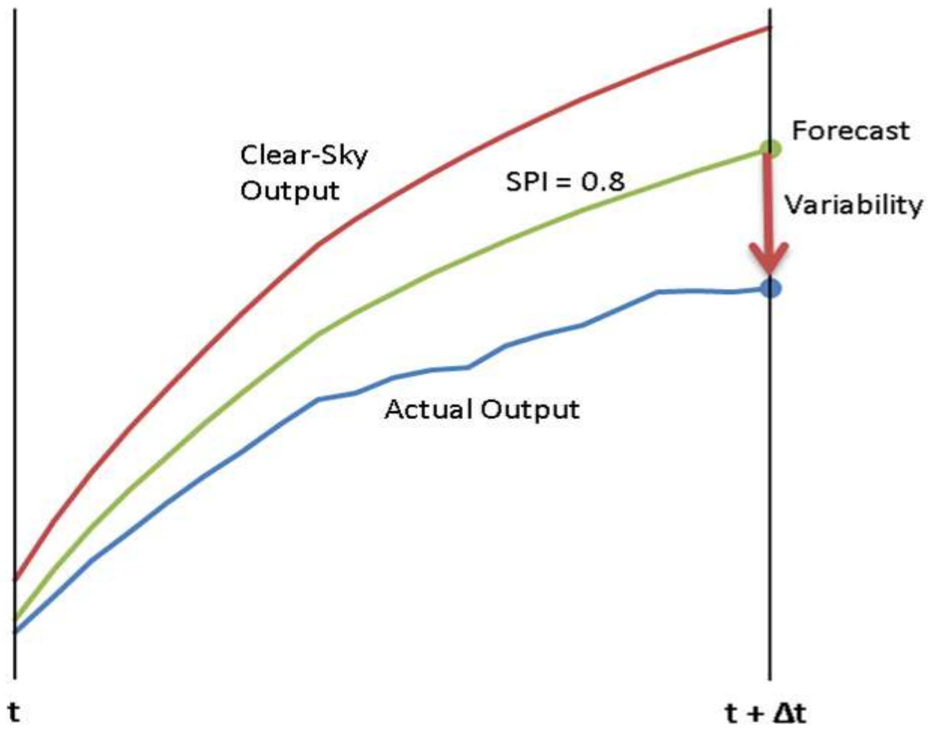
- Variability of solar PV
- 5 minute net load analysis
- Ramping statistics
- Forecast error statistics
- Effect of aggregation on solar and net load variability

Variability of Solar PV Data

- **Conflicts in the definition variability for PV**
  - Arise from evolving notions for solar
  - And time frames
- **To include the arc of the sun, or not…**
  - The variability of PV due to the arc of the sun is perfectly predicable
    - Similar to a known fuel limitation
  - Other factors like clouds passing are not so predictable
    - More like the variability in wind

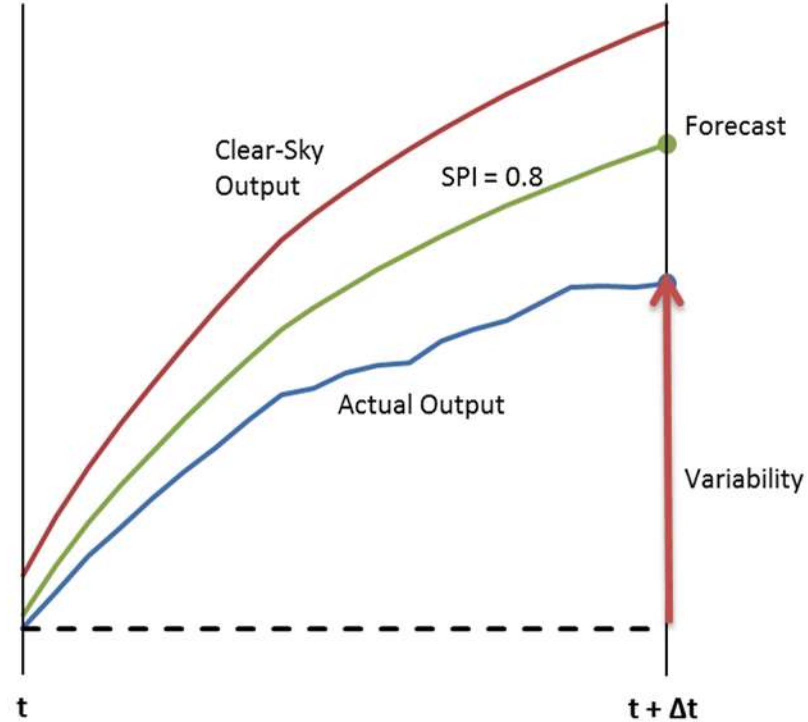
Without the Arc…

- Calculated by forecasting based on cloudiness persistence in the short term (SPI)
- Normally considered in short timeframes (5 minutes to 1 hour)
- Difference between what we expect and what occurs
- Like the variability seen in wind from persistence



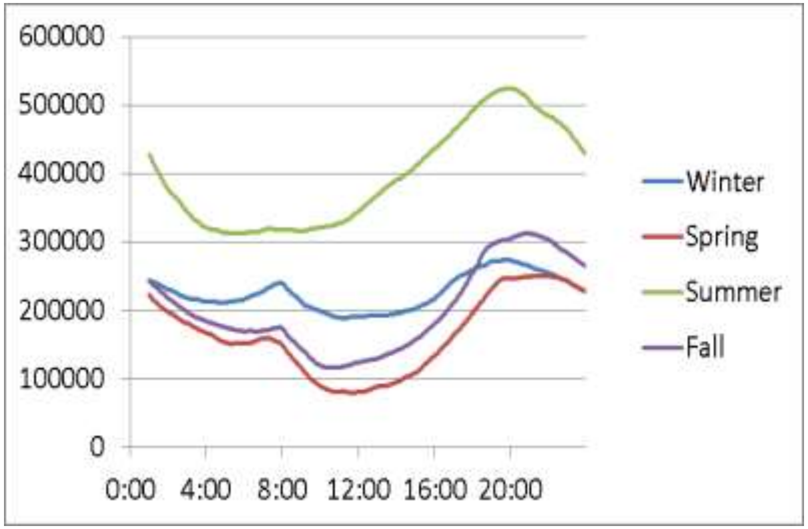
With the Arc…

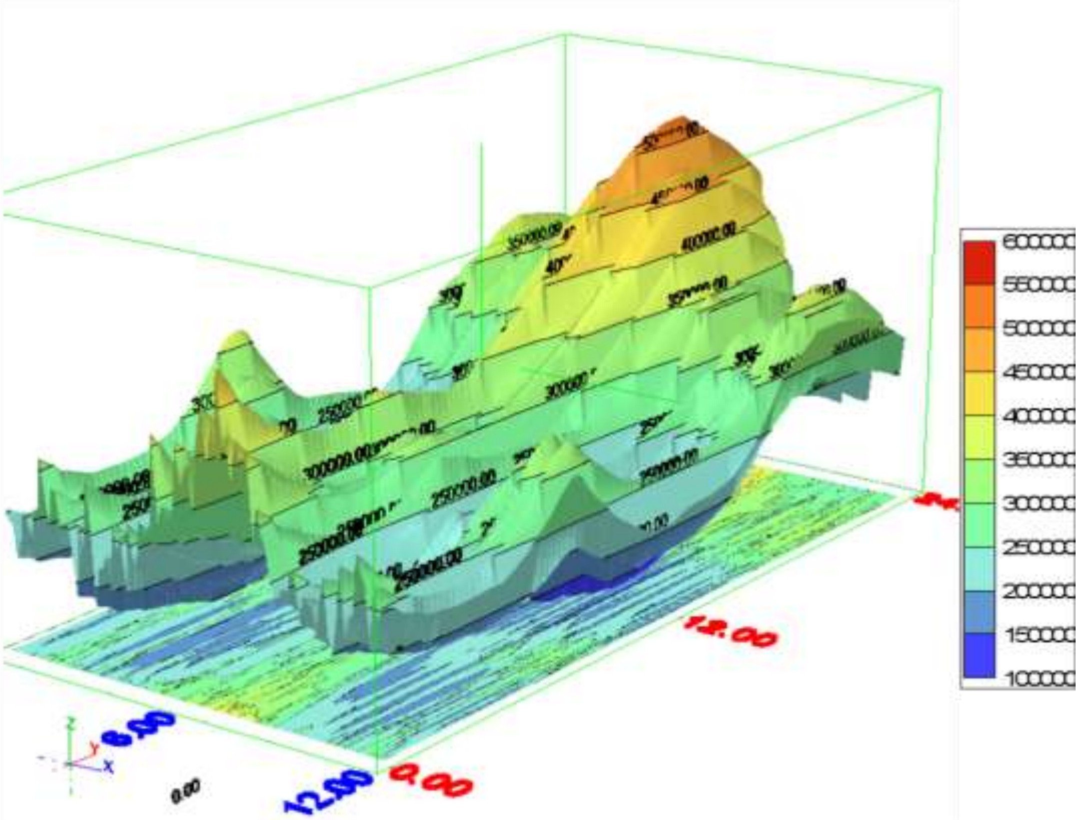
- We see the total change in output that the system will experience
- For net load and system ramps, this seems the proper perspective
- For reserves analysis, since the predicable variability can be scheduled, we use the cloudiness persistence calculation



Regional Scenario Net Load in the EI

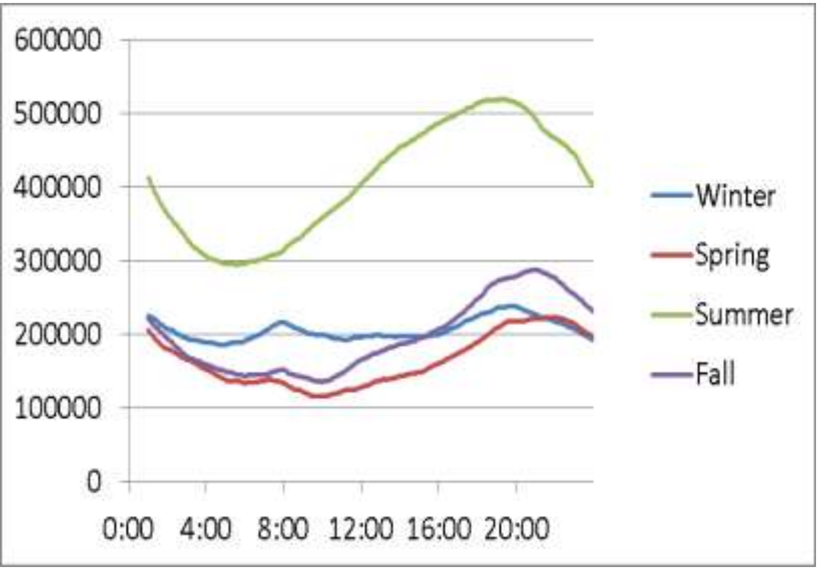
- **20% wind and 10% solar overall**
  - SERC 15% solar, FRCC 30%, rest is 5%
- **Peak net load in early evening year round**
  - Several hours later than traditional peak
- **Strong double peaks in winter**
- **X-axis is month, Y-axis is time**

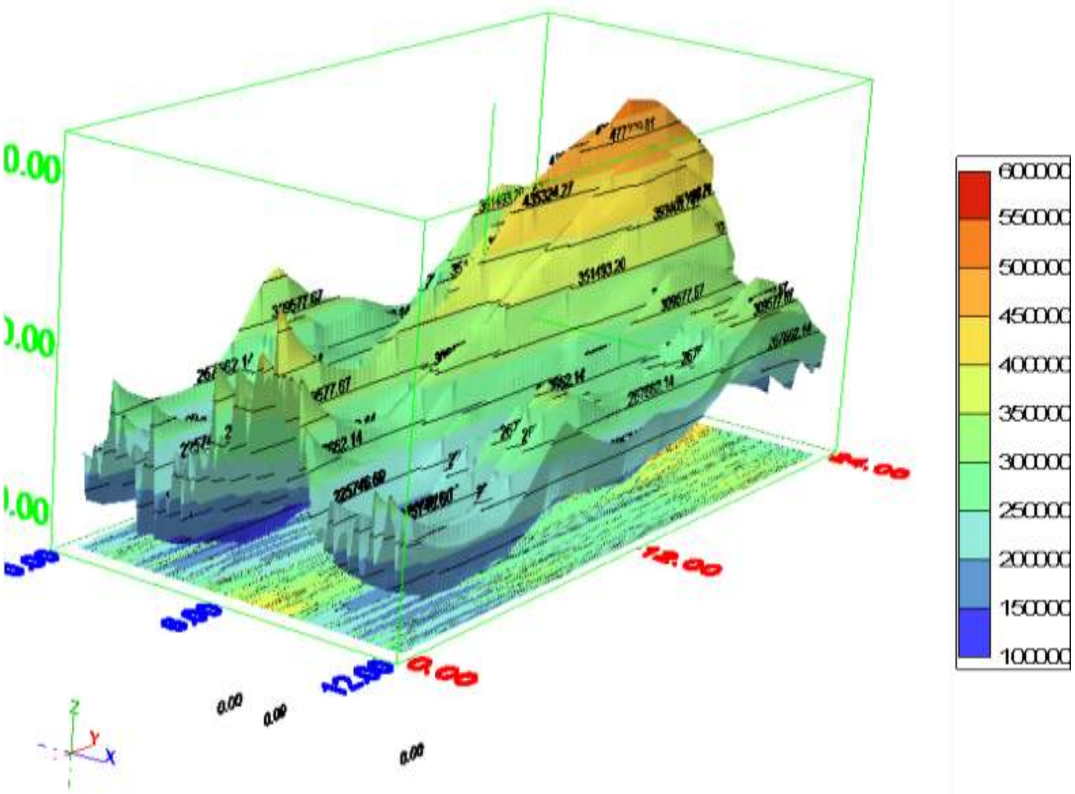




National Scenario Net Load in the EI

- **25% wind, 5% solar overall**
- **More typical load profile**
- **Peak is earlier than Regional Scenario**
- **Sunrise trough not seen in the summer**



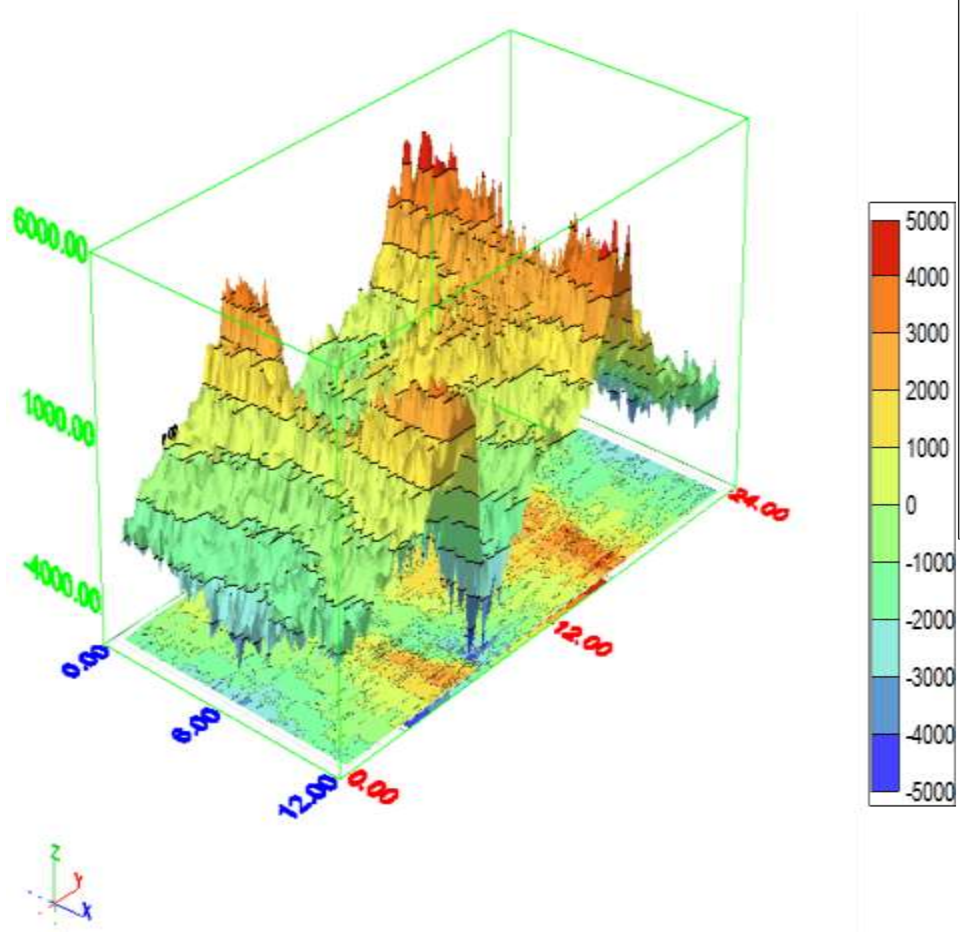


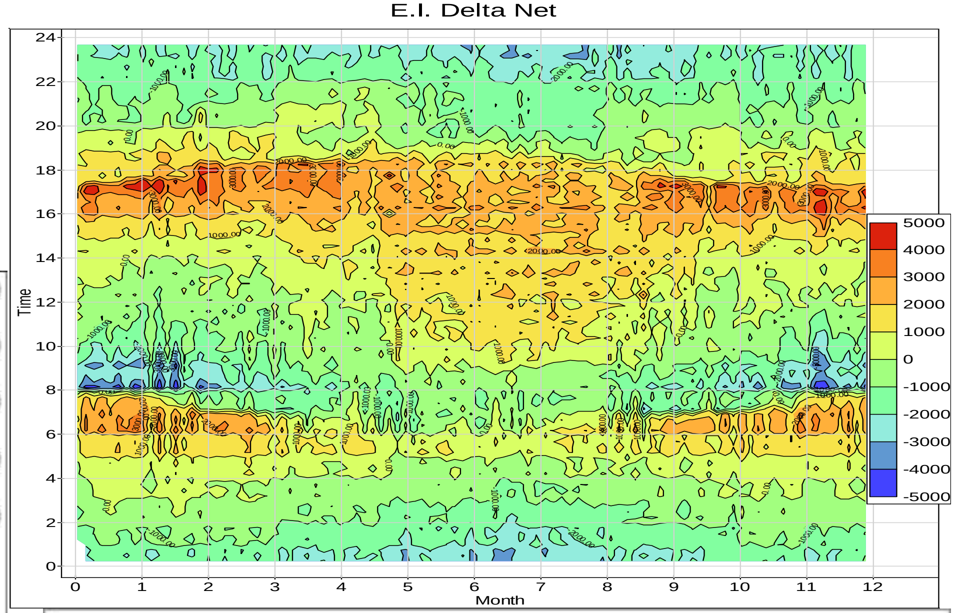
5-Minute Ramp Statistics

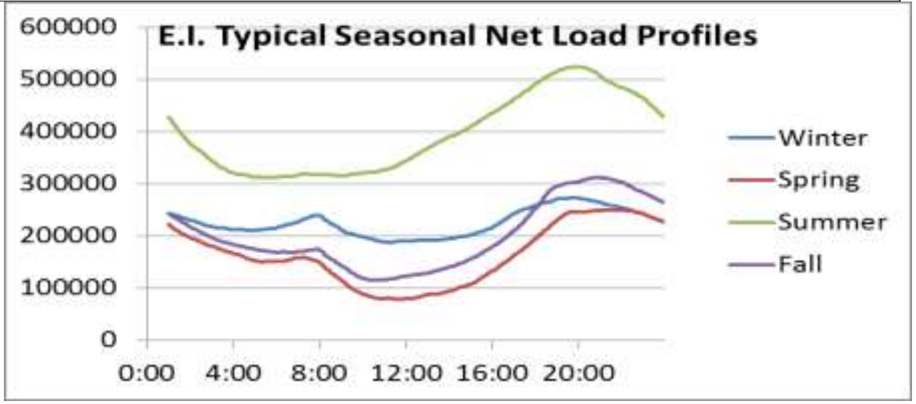
	FRCC	ISO-NE	MISO	NYISO	PJM	SERC	SPP	EI
Max Negative Delta (MW/5 Minutes)								
Load Alone	-579	-313	-1021	-303	-1245	-1040	-405	-3692
Current VG	-579	-315	-1025	-307	-1285	-1040	-420	-3752
State RPS	-601	-369	-1222	-417	-1471	-1059	-909	-4153
Regional Scenario	-2547	-407	-1445	-421	-1951	-2921	-1217	-6237
National Scenario	-1885	-374	-1707	-445	-1905	-1393	-1409	-5133
Max Positive Delta (MW/5 Minutes)								
Load Alone	562	336	977	316	1270	1020	385	3654
Current VG	562	335	1001	319	1280	1020	396	3700
State RPS	562	388	1261	435	1361	1087	726	3924
Regional Scenario	2577	412	1556	411	1612	2871	1097	6654
National Scenario	2053	392	2031	429	1504	1392	1430	4592
Number of Drops < -3 * Load Sigma								
Load Alone	57	194	46	138	79	27	59	0
Current VG	57	208	57	156	91	28	118	2
State RPS	57	445	358	938	161	47	3043	11
Regional Scenario	10787	509	738	641	386	5001	6963	865
National Scenario	6054	466	1311	899	267	239	12140	174
Number of Rises > 3 * Load Sigma								
Load Alone	31	70	48	57	46	31	119	0
Current VG	31	75	79	69	49	32	196	3
State RPS	32	215	336	512	105	46	3630	34
Regional Scenario	10787	509	738	641	386	5001	6963	865
National Scenario	3495	309	1522	737	224	150	12439	110

5 Minute Net Load Ramps – Full EI, Regional Scenario

- **Showing midday lull in variability (light yellow and light green) with morning load ramp, sunrise drop and prominent sunset increase**
- **In summer, better coordination between morning ramp and sunrise ramp reducing the upward ramp**

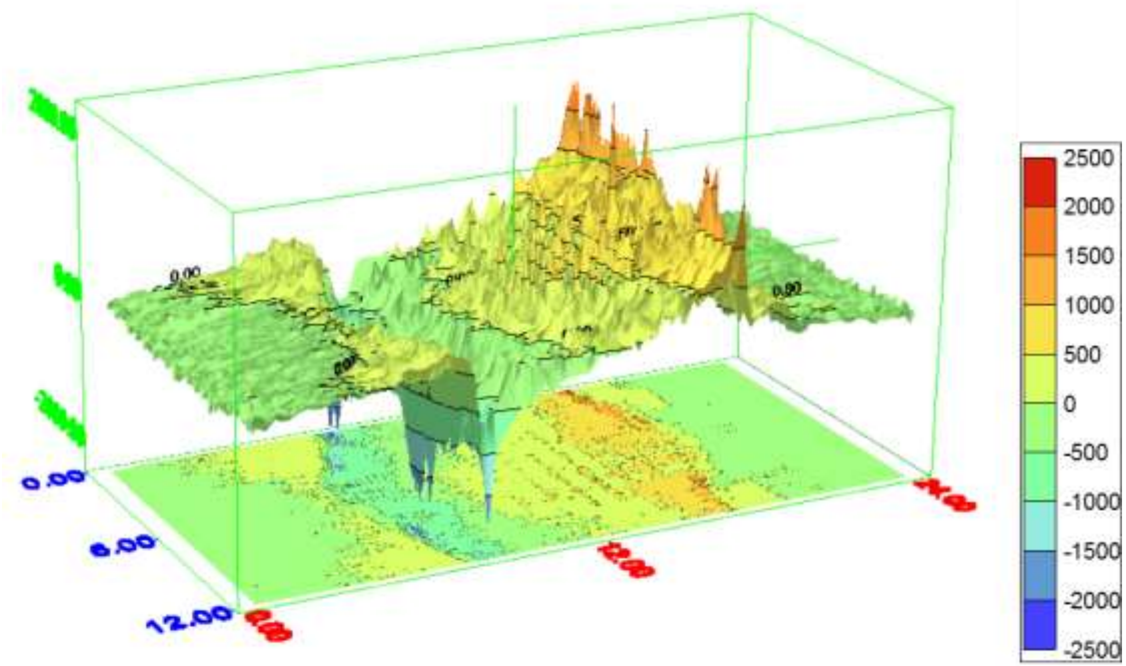


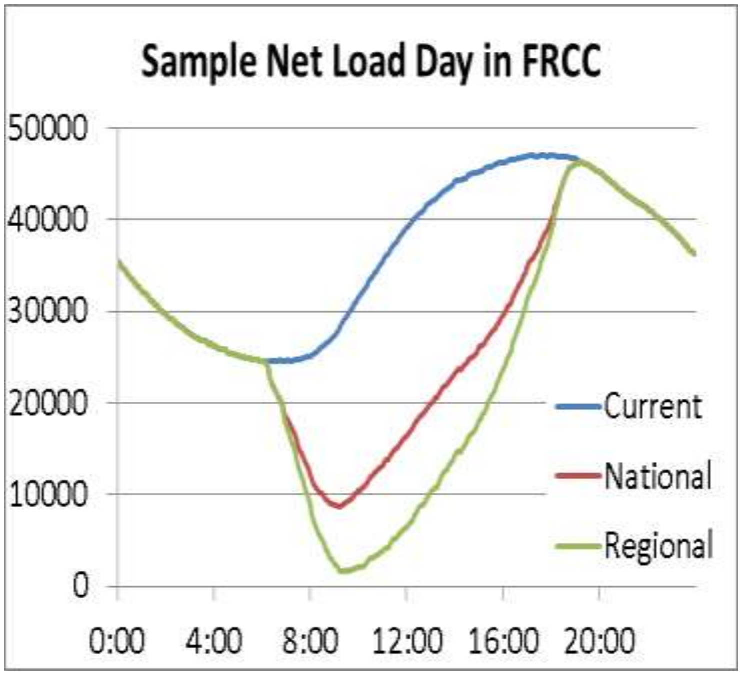




FRCC Regional Scenario Net Load Ramps

- Very little expression of normal load profile during the day for high penetration scenarios
- Because of the required penetration, 30% all solar, morning net load goes near 0 (or negative) with very steep ramps
- Sunset ramps aggravated by increasing load and decreasing solar production
- Ramps are steepest in the off-peak seasons
- Peak slightly delayed compared to current scenario





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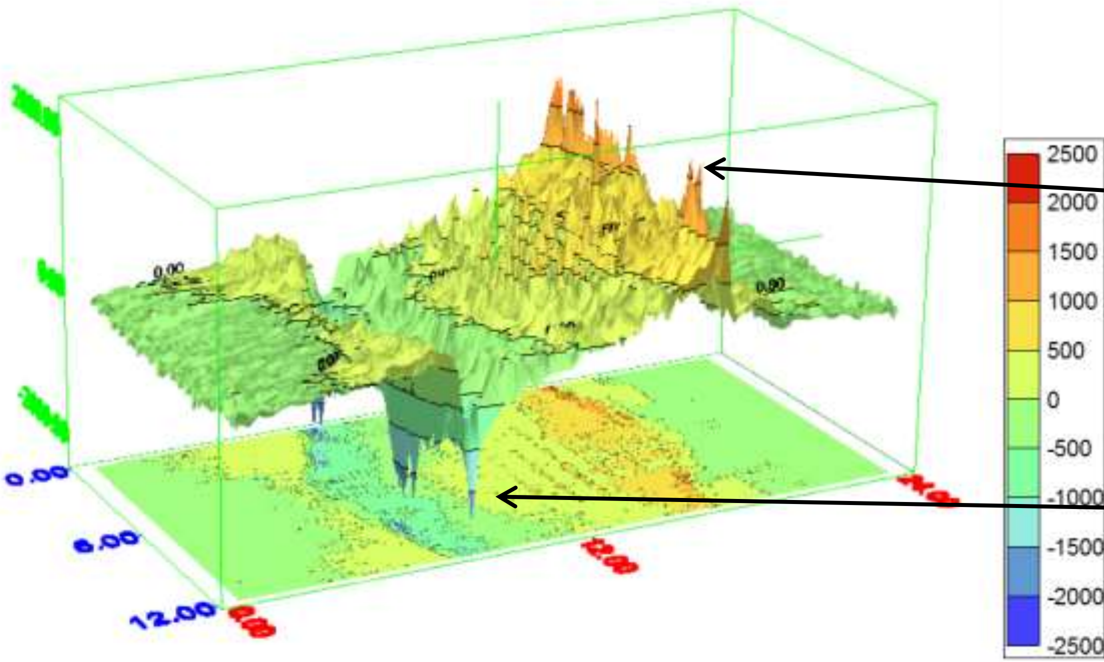
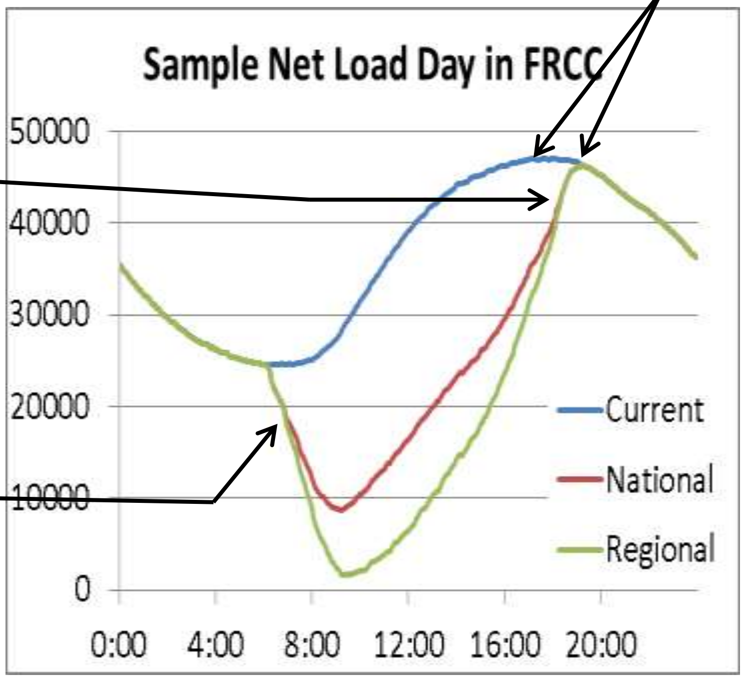
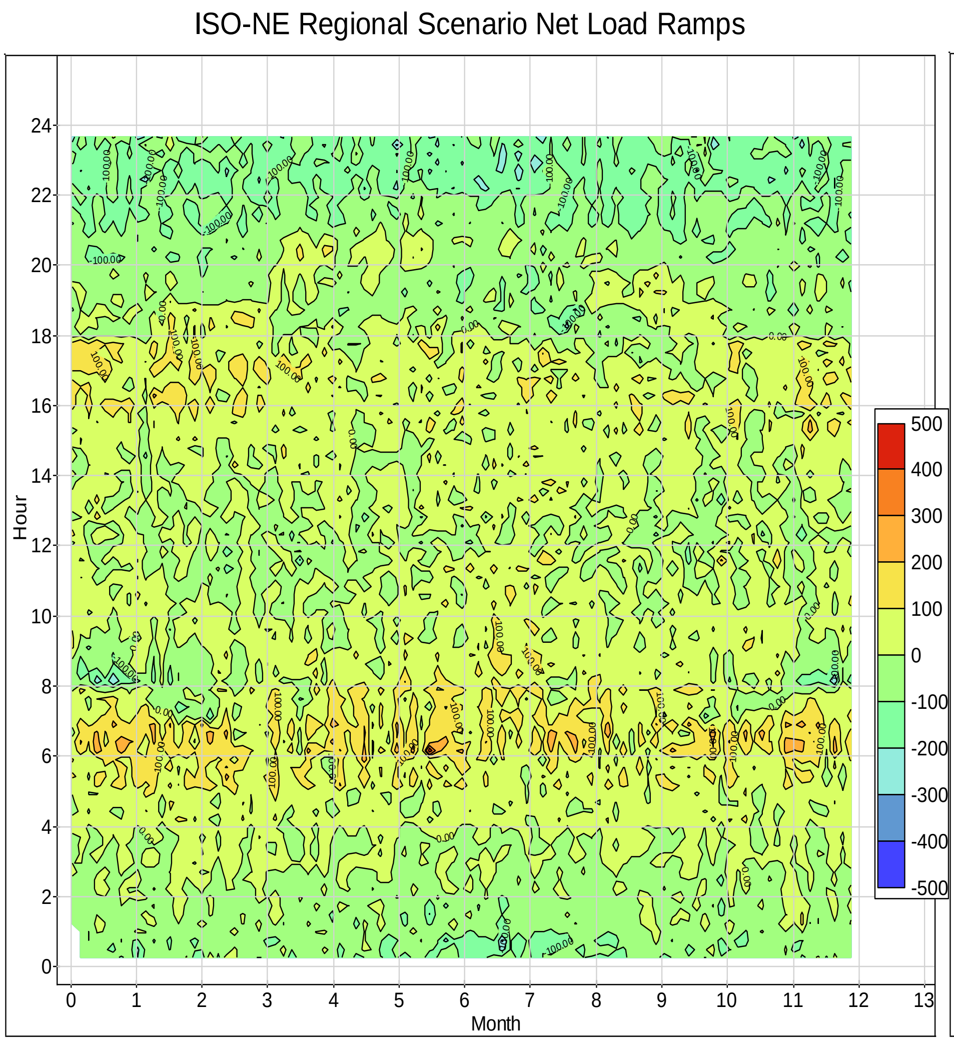
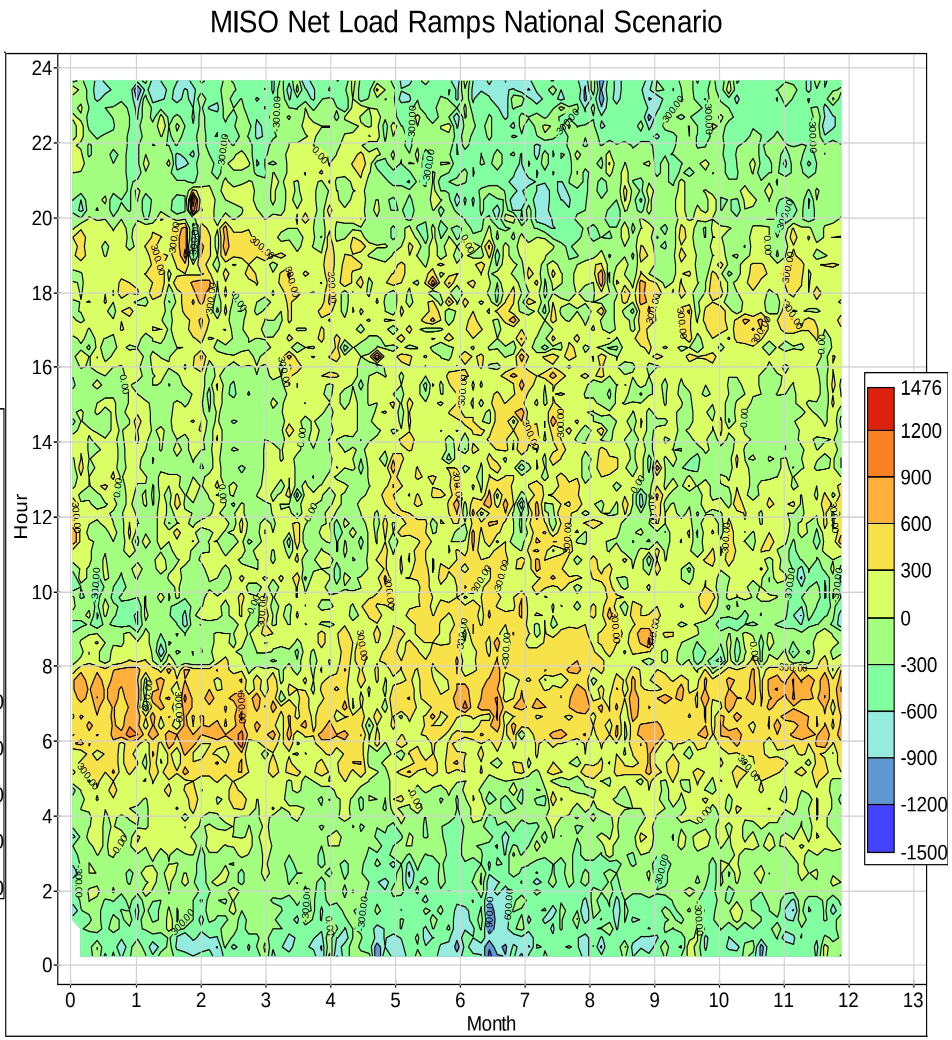




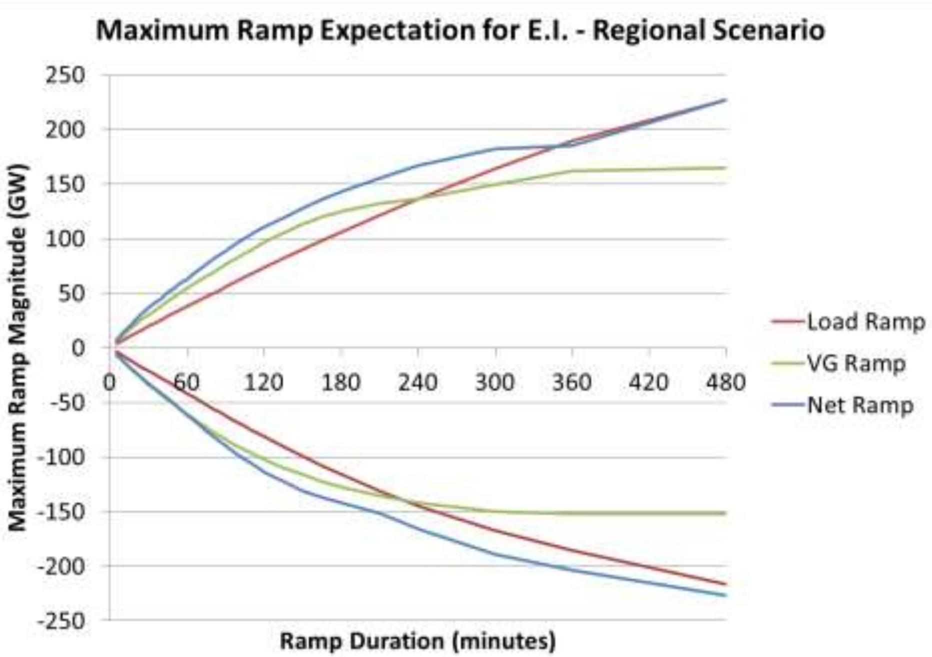
Regional Net Load Ramps

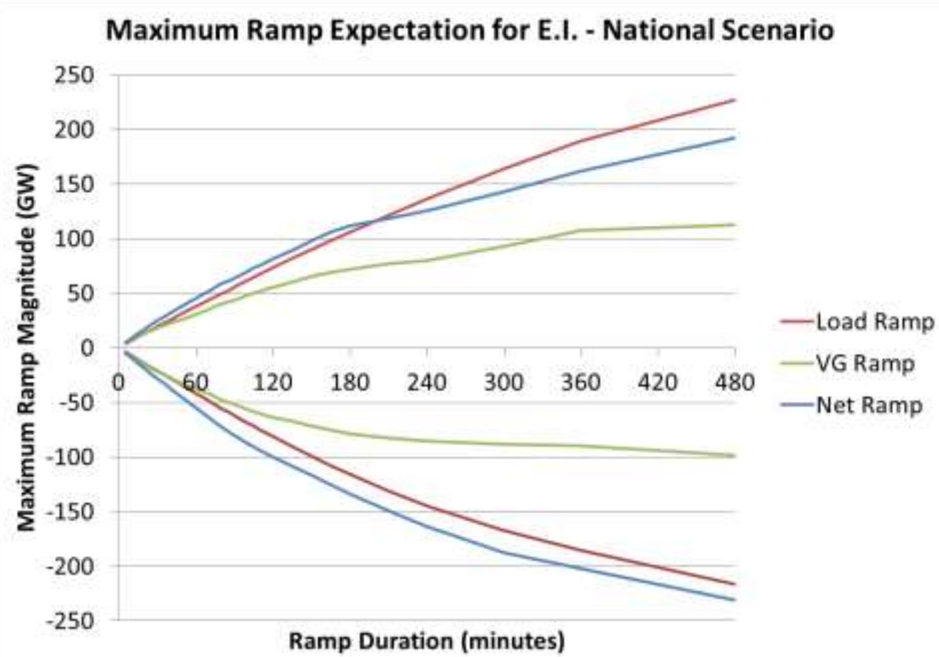




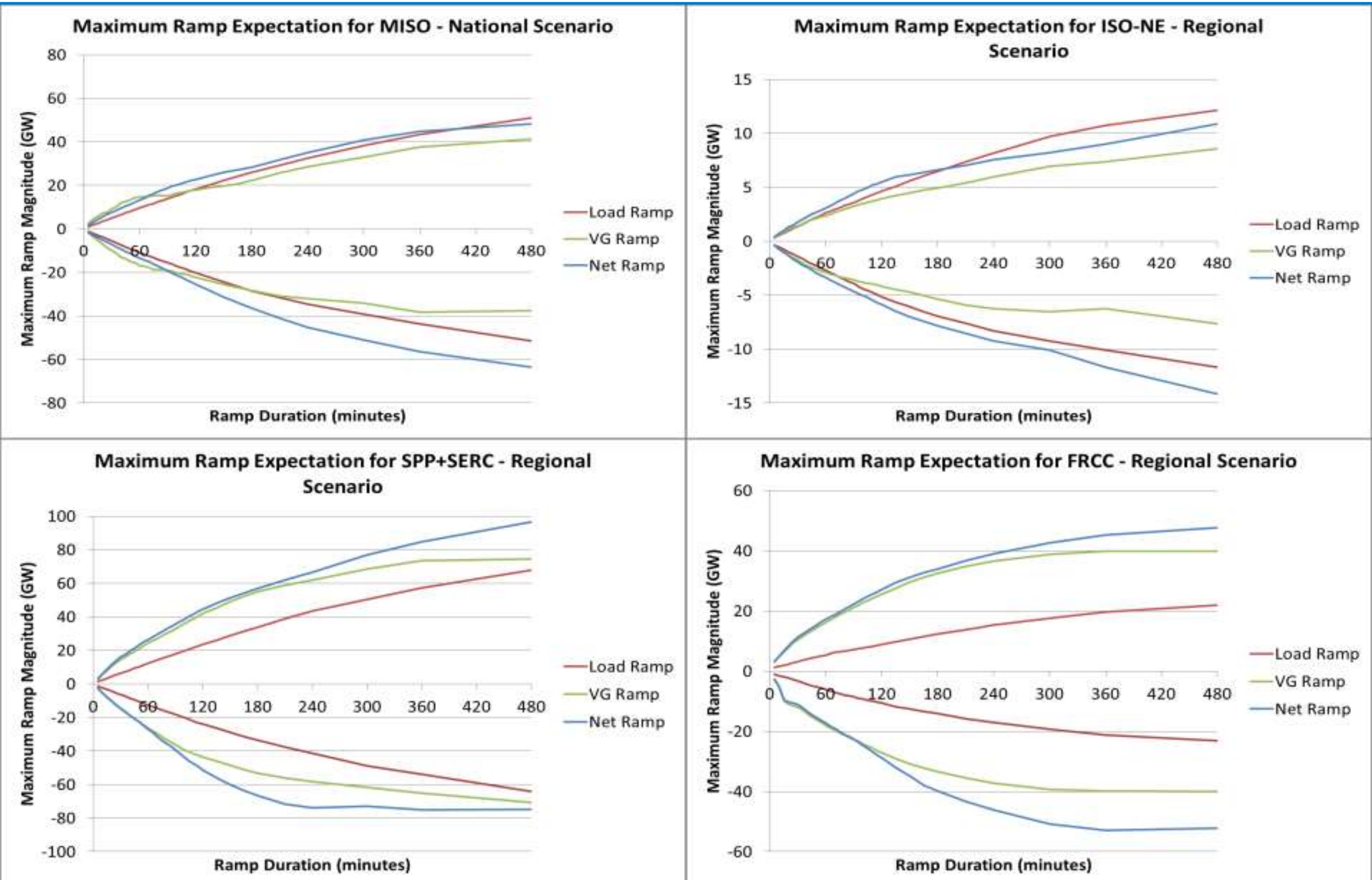
EI Maximum Ramp Expectation

- **Predicts largest ramps that will be seen**
- **Regional Scenario**
  - Up to around 4 hours, the net ramp is dominated by VG ramp, above 4 hours, load ramp is dominant
- **National Scenario**
  - Net ramp is dominated by load with VG actually lowering positive ramps at longer periods
  - Lower solar penetration (5%) reduces VG ramps by 50 MW at 8 hrs
- **99.995th percentile eliminates some known PV artifacts**





Regional Ramp Expectations



Day-Ahead Forecast Error Statistics

- Regional scenario
- Net load normalized to peak load value, wind and solar to nameplate
- Net load error = -(WindError + SolarError) with no load error

	FRCC	ISO-NE	MISO	NYISO	PJM	SERC	SPP	EI
				Wind Forecasts				
Wind Cap (MW)	0	9960	52028	11448	47128	14322	46601	181487
MAE	0	939	3673	1113	3238	1836	4259	8247
	0%	9.4%	7.1%	9.7%	6.9%	12.8%	9.1%	4.5%
RMSE	0	1167	4527	1375	4113	2275	5294	10264
	0%	11.7%	8.7%	12.0%	8.7%	15.9%	11.4%	5.7%
				Solar Forecasts				
Solar Cap (MW)	52137	5675	36199	6355	33624	73762	10457	218209
MAE	3669	427	2470	530	2277	4786	716	12320
	7.0%	7.5%	6.8%	8.3%	6.8%	6.5%	6.8%	5.6%
RMSE	4665	587	3191	719	3055	6172	908	15840
	8.9%	10.4%	8.8%	11.3%	9.1%	8.4%	8.7%	7.3%
				Net Load Forecasts (Assumes perfect load forecast)				
Load (MW)	50673	29208	152401	34762	187818	140619	50226	636109
MAE	3669	998	4077	1170	3574	3426	4276	19407
	7.2%	3.4%	2.7%	3.4%	1.9%	2.4%	8.5%	3.1%
RMSE	4665	1231	5047	1436	4555	4777	5286	21402
	9.2%	4.2%	3.3%	4.1%	2.4%	3.4%	10.5%	3.4%

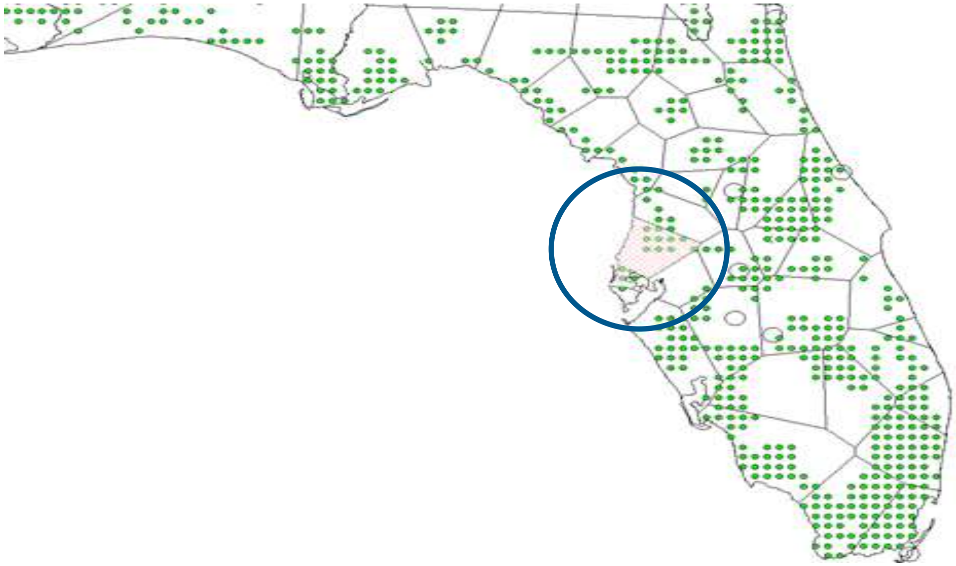
4-Hour-Ahead Forecast Error Statistics

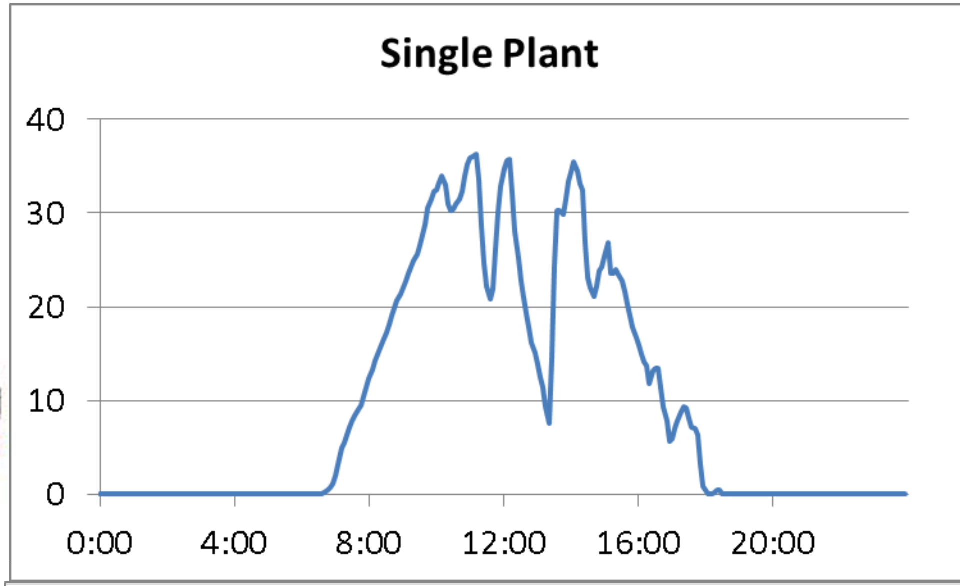
		FRCC	ISO-NE	MISO	NYISO	PJM	SERC	SPP	EI
Wind Forecasts									
Wind Cap (MW)		0	9960	52028	11448	47128	14322	46601	181487
MAE		0	765	2923	901	2681	1532	3373	6655
		0%	7.7%	5.6%	7.9%	5.7%	10.7%	7.2%	3.7%
RMSE		0	965	3646	1127	3432	1969	4261	8369
		0%	9.7%	7.0%	9.8%	7.3%	13.8%	9.1%	4.6%
Solar Forecasts									
Solar Cap (MW)		52137	5675	36199	6355	33624	73762	10457	218209
MAE		1667	252	885	257	1015	2087	318	4060
		3.2%	4.4%	2.4%	4.0%	3.0%	2.8%	3.0%	1.9%
RMSE		2742	440	1580	431	1859	3846	557	7748
		5.3%	7.8%	4.4%	6.8%	5.5%	5.2%	5.3%	3.6%
Net Load Forecasts (Assumes perfect load forecast)									
Load (MW)		50673	29208	152401	34762	187818	140619	50226	636109
MAE		1667	799	3065	923	2823	2196	3392	14054
		3.3%	2.7%	2.0%	2.7%	1.5%	1.6%	6.8%	2.2%
RMSE		2742	1014	3845	1157	3655	3444	4283	15699
		5.4%	3.5%	2.5%	3.3%	1.9%	2.4%	8.5%	2.5%

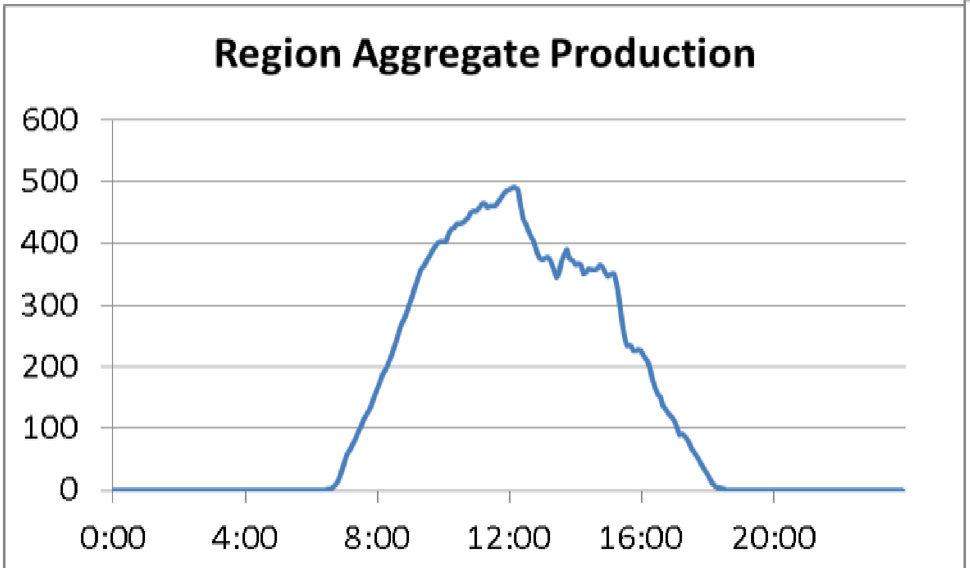
Net Load Variability Aggregation

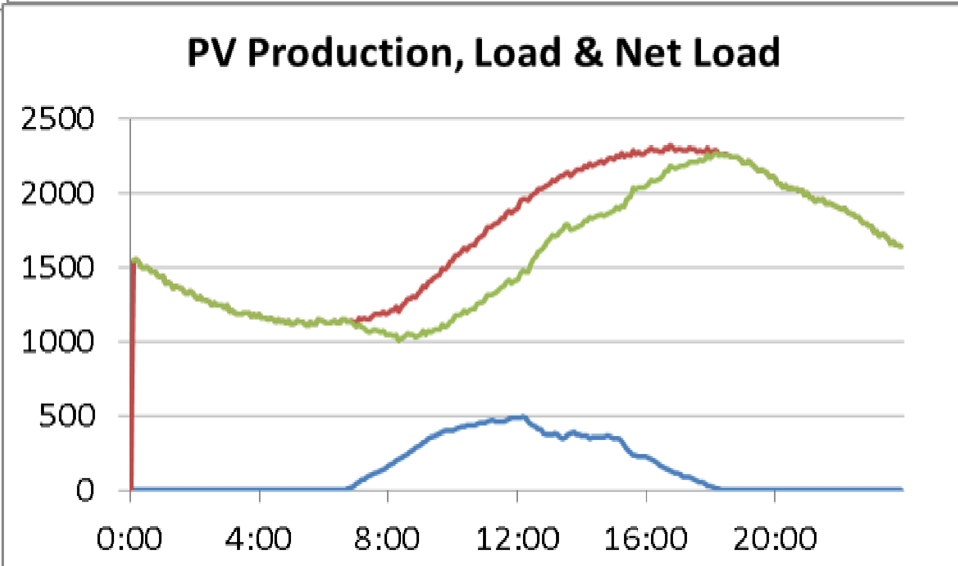
- **Regions in Florida to demonstrate the aggregation effects on variability**
- **Selected a particularly variable summer day**
- **Compare**
  - Single plant
  - 800 MW in 13 plants with 2,800 MW of load
  - 3,750 MW in 51 plants with 11,400 MW of load

Variability in a Small Region…

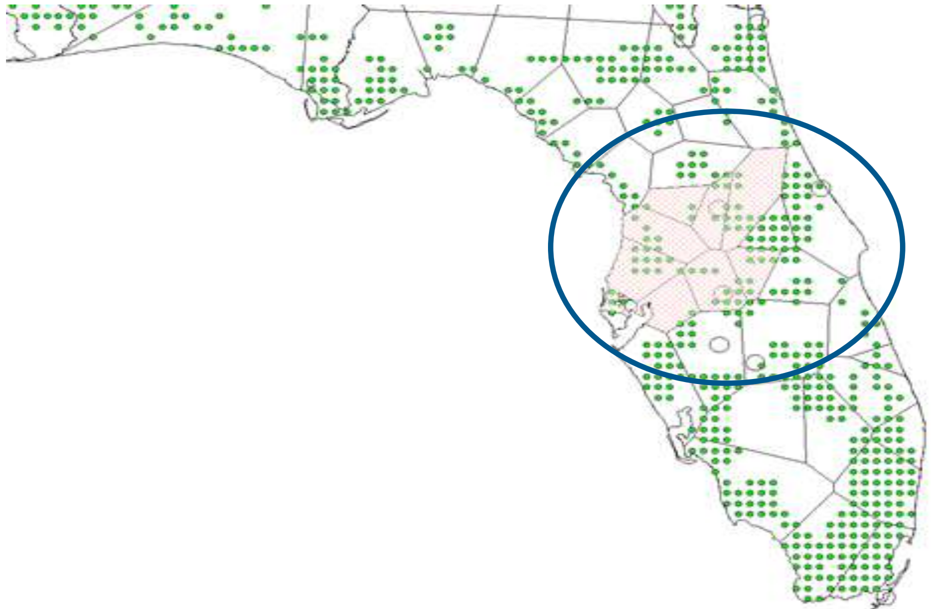


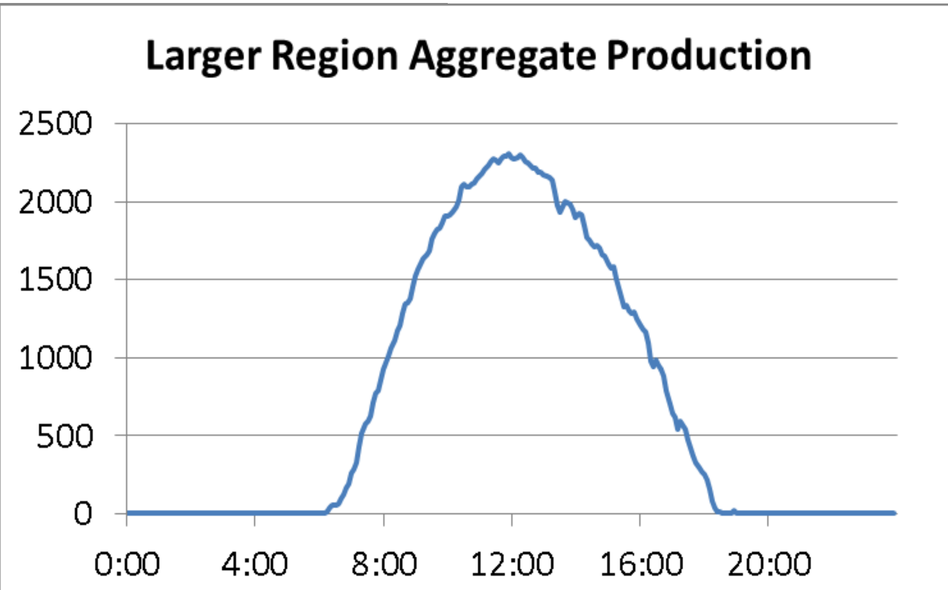


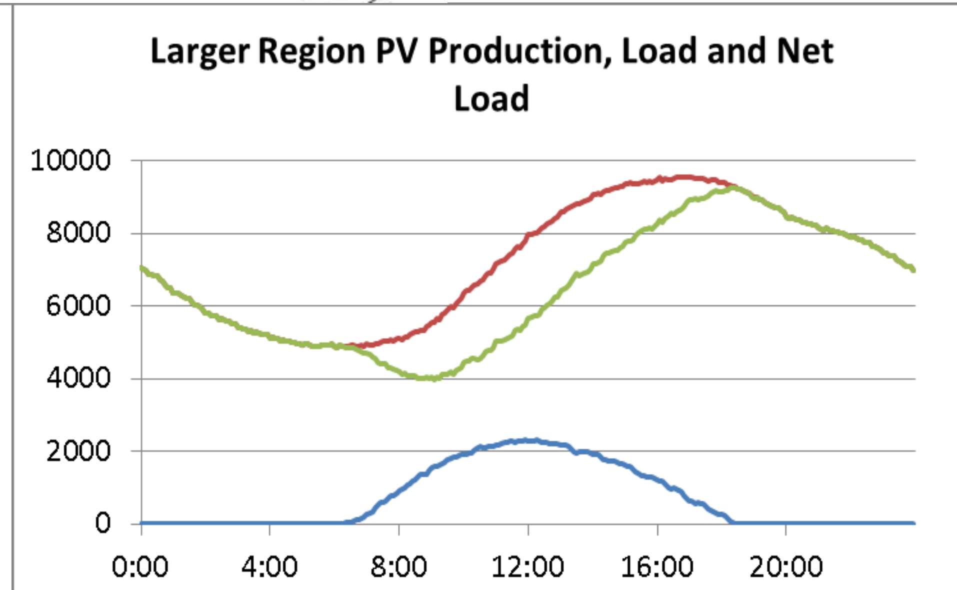




Larger Region







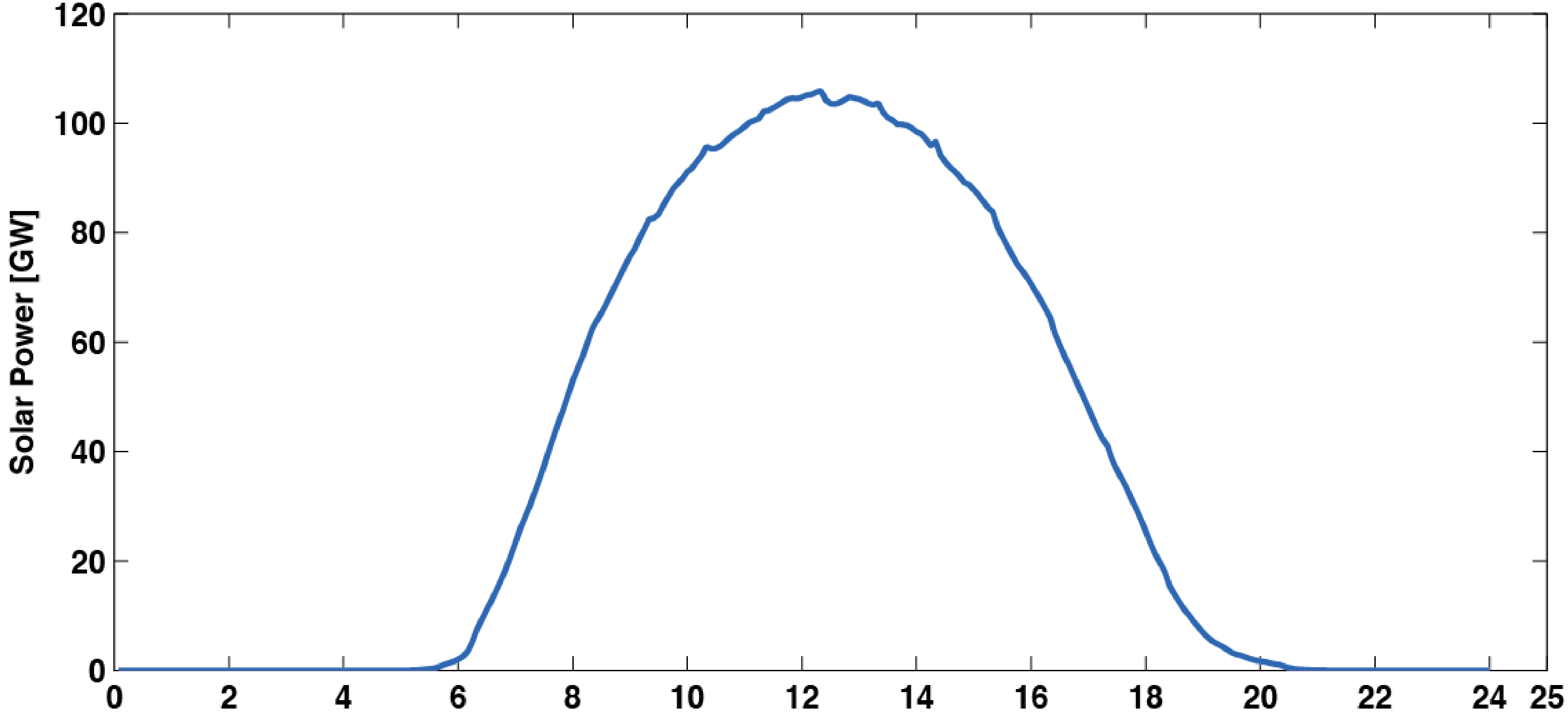
Visualization of Net Load

- See sample video

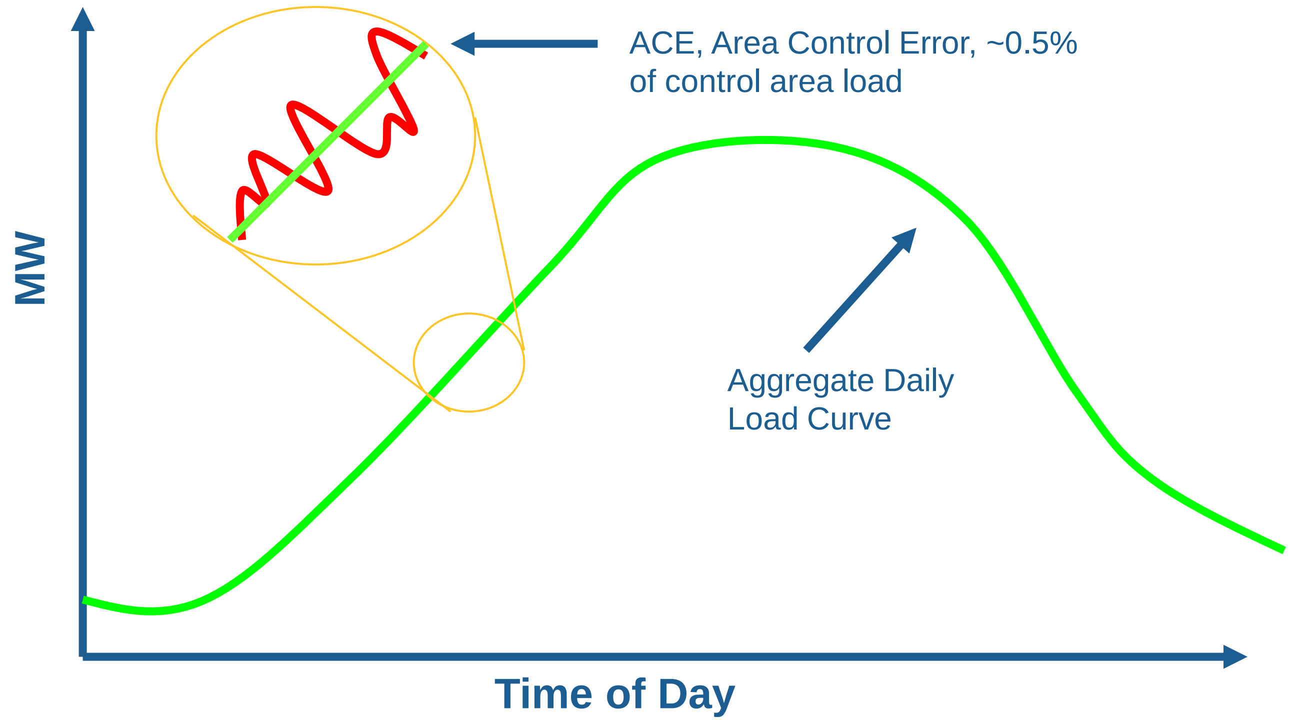
Reserves

5-Minute Solar Power Data

- See sample video



Objective of Modeling Reserves



Operating reserves allow the system to respond to forecast errors and unexpected events. Modeling reserves changes the unit commitment and production cost of energy.

- **Contingency:** Events
- **Regulation reserves:** Second to minute variations

Objective of Modeling Reserves

Economic consequences of holding capacity for reserves comes from changing the "economic dispatch" that serves load to include spinning/committed capacity to provide both energy and capacity, during each time step.

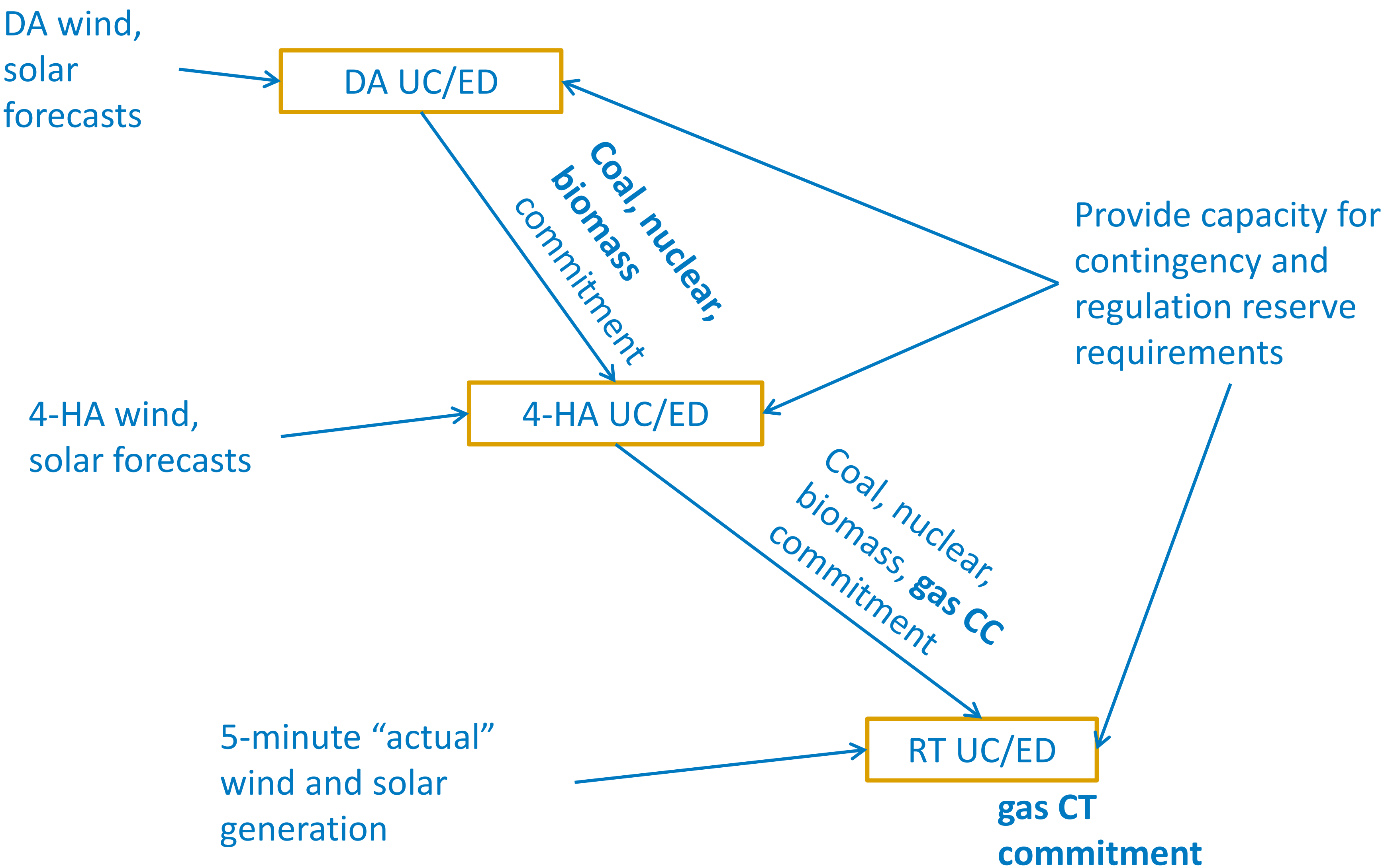
Factors that affect the cost of modeled reserves:

- **total reserve requirements**
- **size of the reserve sharing group**
- operating characteristics of generators
- number of generators willing to provide reserves
- bid/cost adder for "wear and tear" of providing regulation

Modeling Reserves: Types

- **Contingency reserves**
  - 3% load (varies by hour) or largest single contingency
- **Regulation reserves**
  - Sum of 1% load and 95% of the 10-minute forecast error for wind and PV generation

Modeling Reserves: Market Sequence



Regulation Reserve Requirements

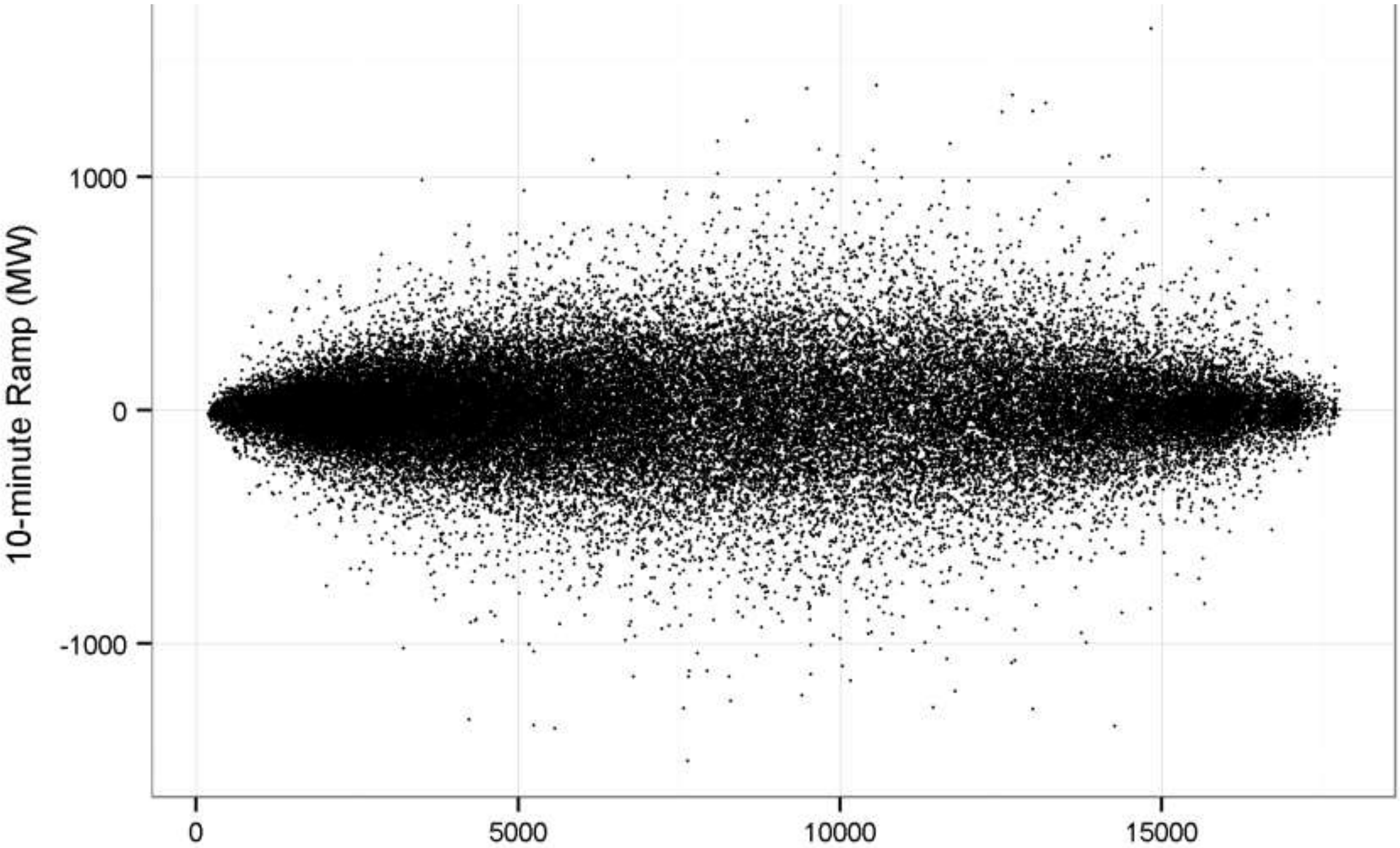
- **Calculate the Wind Power Reserves**
  - Based on EWITS:

  Ela, E.; Kirby, B.; Lannoye, E.; Milligan, M.; Flynn, D.; Zavadil, B.; O'Malley, M. (2010). Evolution of Operating Reserve Determination in Wind Power Integration Studies, Power and Energy Society General Meeting 2010 IEEE, 25-29 July 2010.

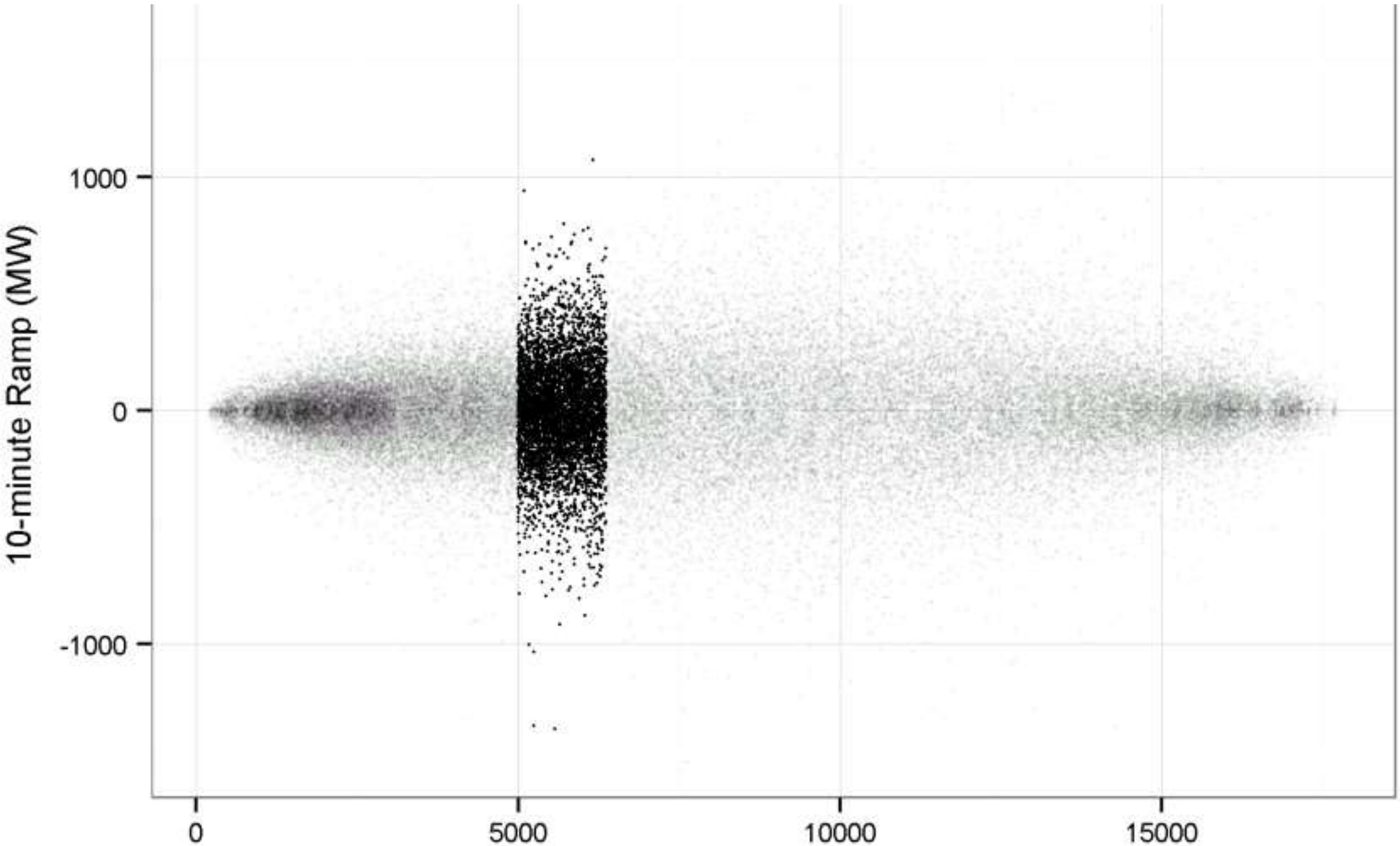
- **Calculate the Solar Power Reserves**
  - Based on WWSIS-II Methodology:

  Ibanez, E.; Brinkman, G.; Hummon, M.; Lew, D. (2012). Solar Reserve Methodology for Renewable Energy Integration Studies Based on Sub-Hourly Variability Analysis: Preprint. 8 pp.; NREL Report No. CP-5500-56169.

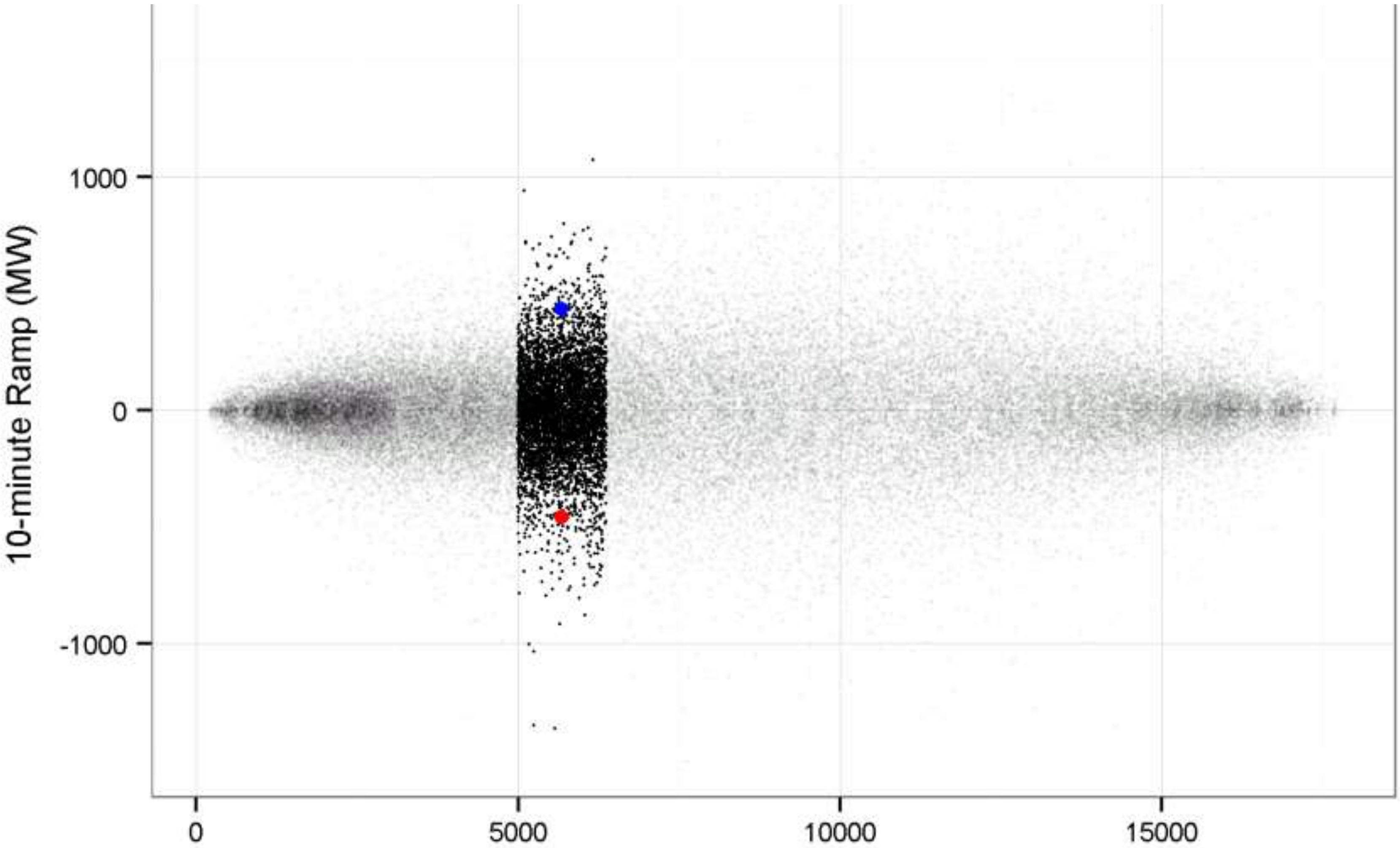
Wind Regulation Reserve Method (1/6)



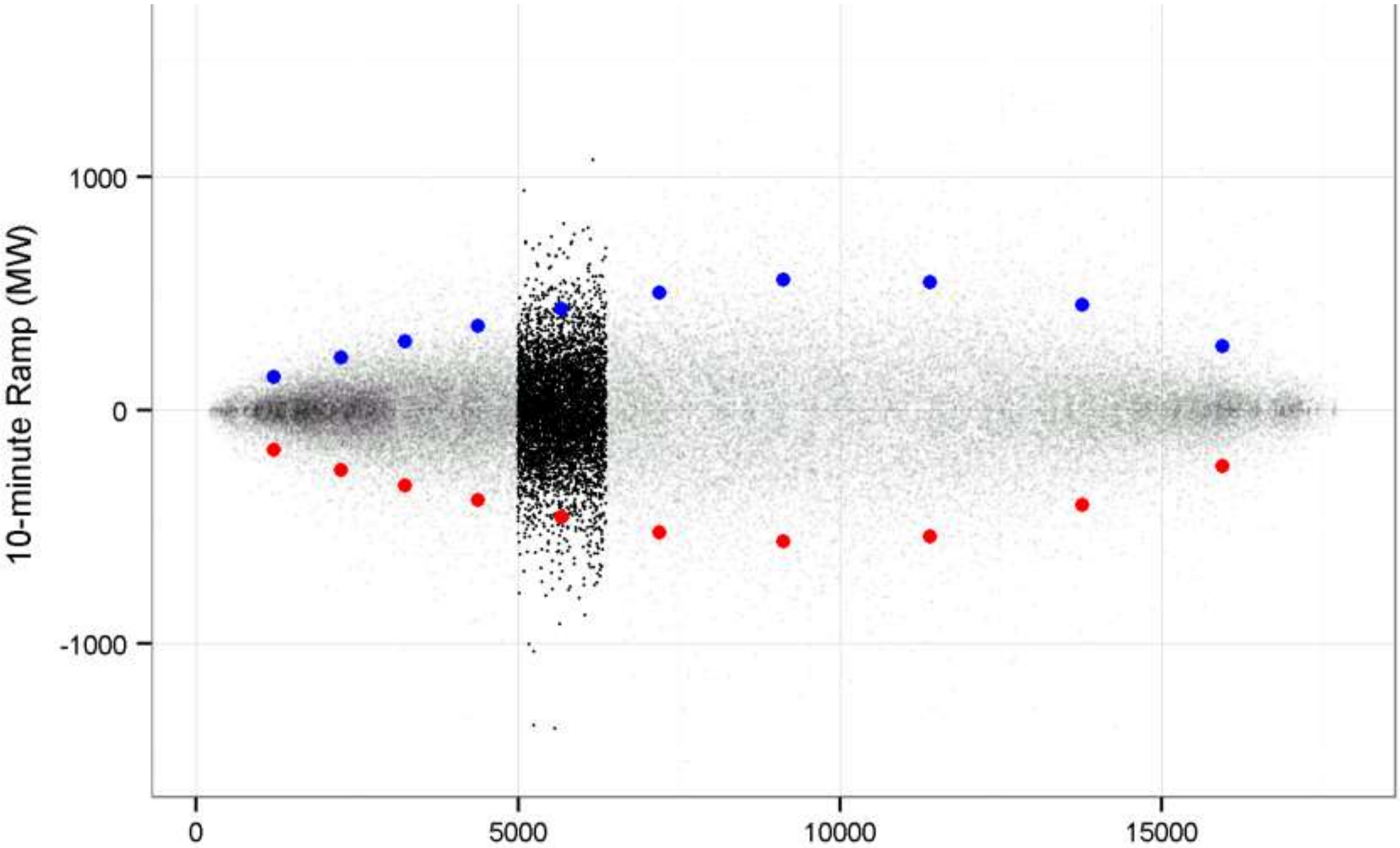
Wind Regulation Reserve Method (2/6)



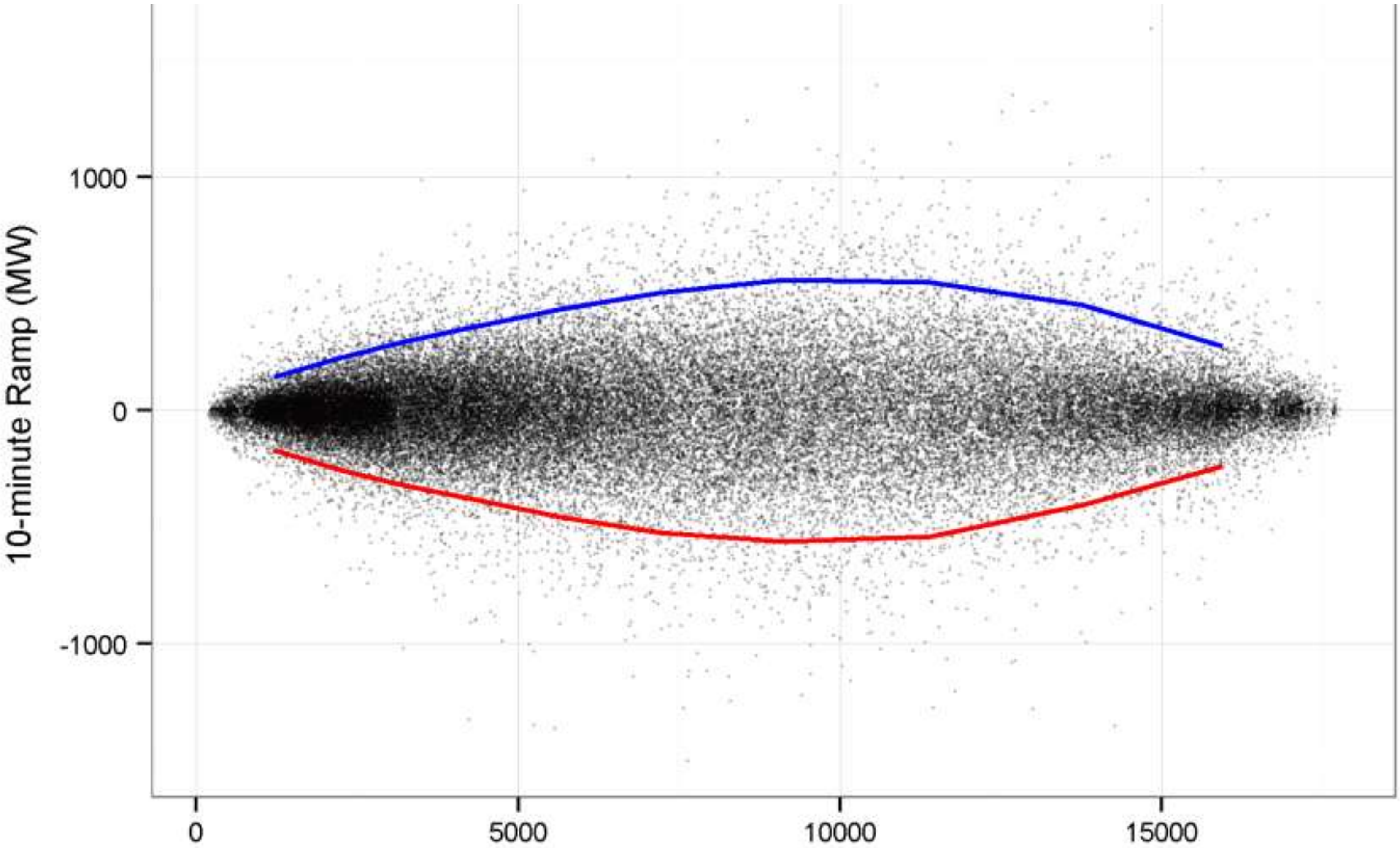
Wind Regulation Reserve Method (3/6)



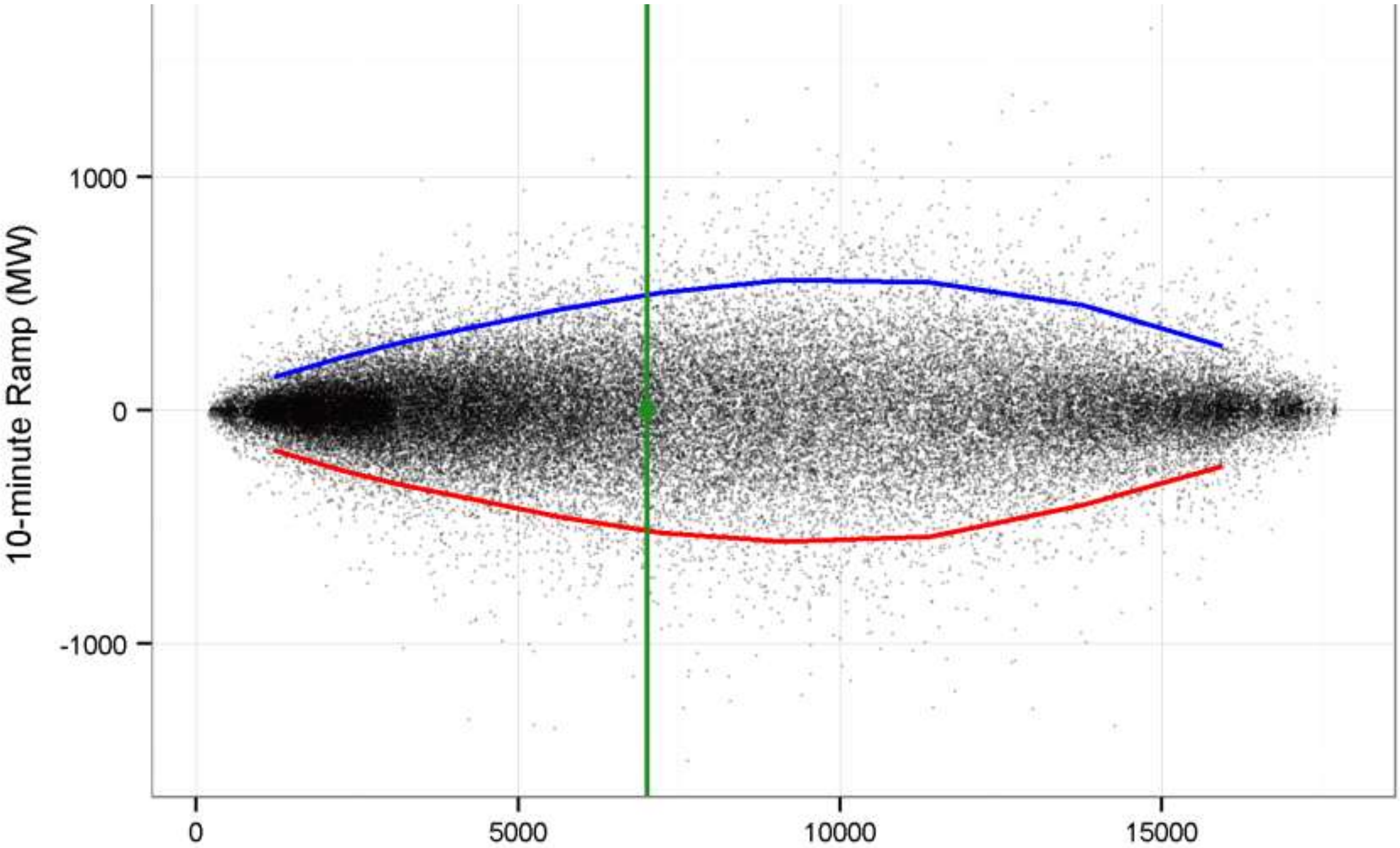
Wind Regulation Reserve Method (4/6)



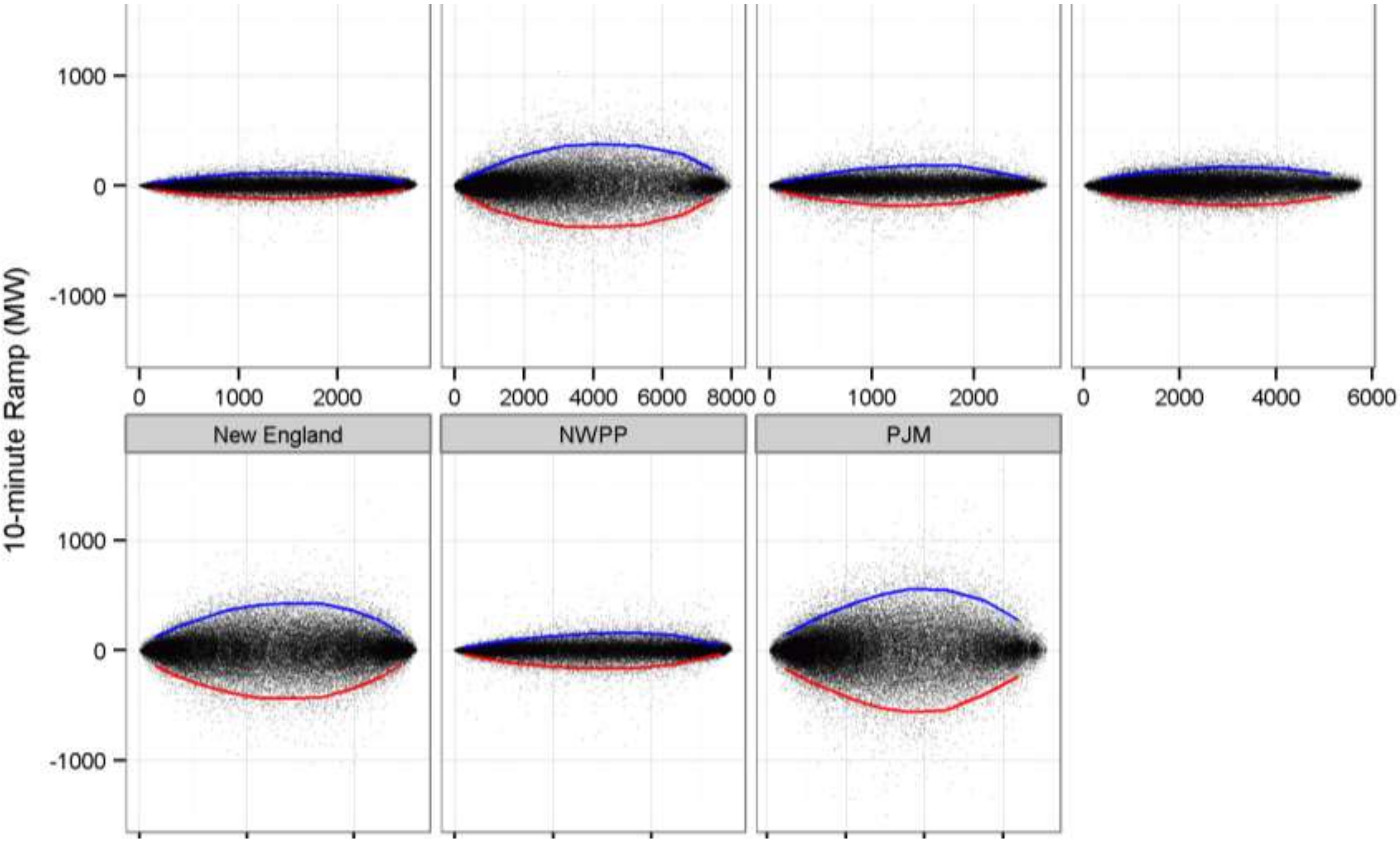
Wind Regulation Reserve Method (5/6)



Wind Regulation Reserve Method (6/6)

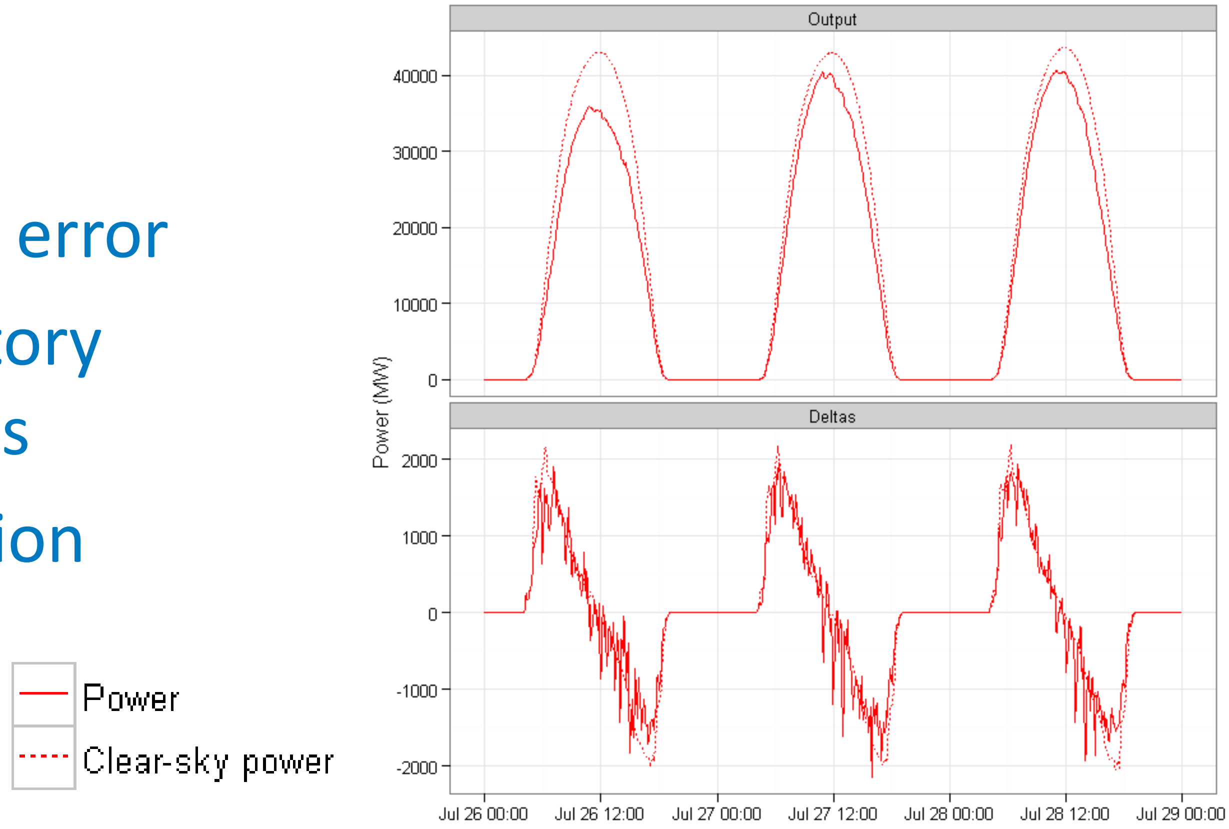


Wind Ramp Distributions Vary by Region



Solar Reserve Methodology

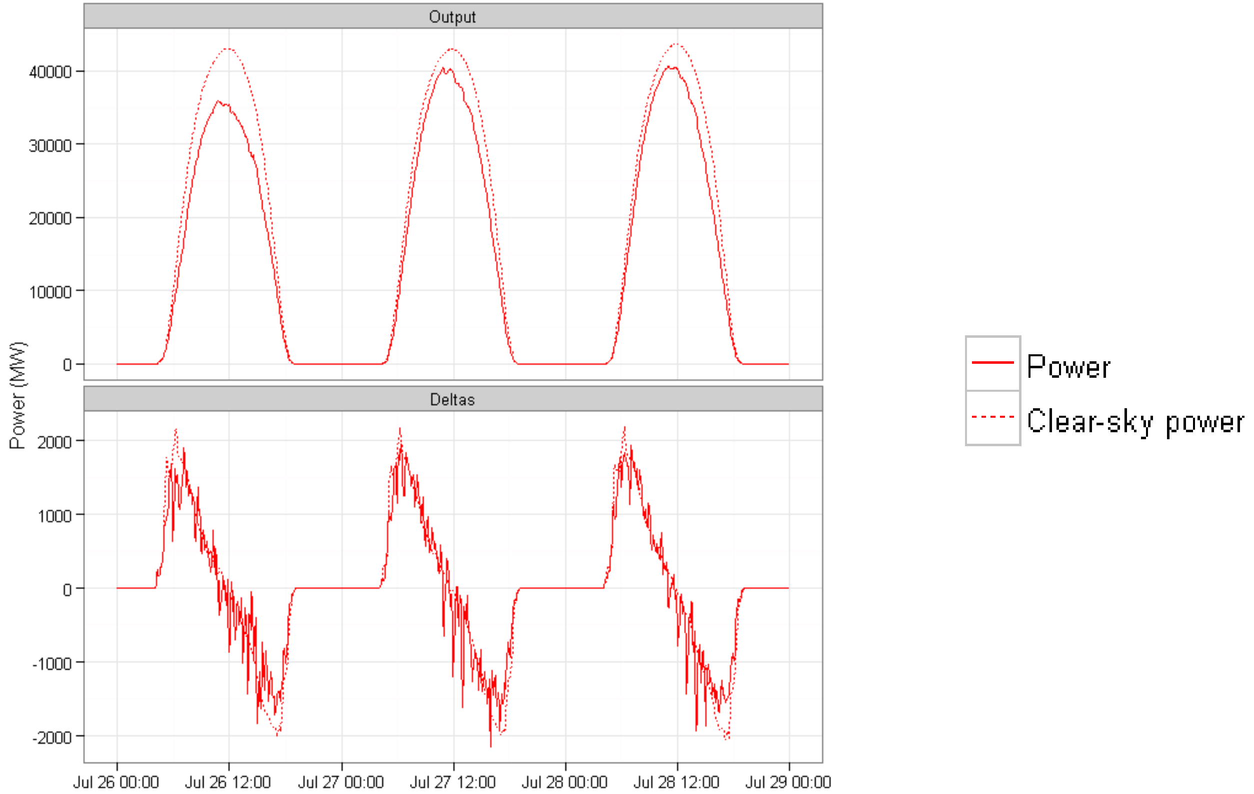
- **Based on wind power method**
- **Need to account for daily variations, which are known**
- **Steps:**
  a) Forecast error
  b) Explanatory variables
  c) Application



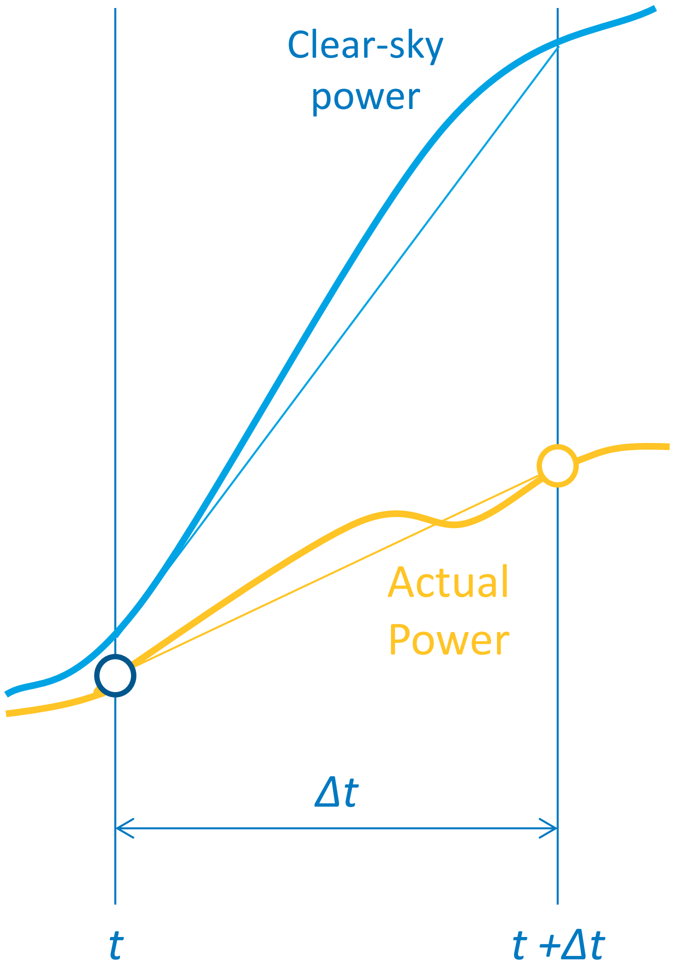
Solar Power Index (SPI)

- **Measures how close to clear-sky conditions**

SPI = Power / Clear-Sky Power

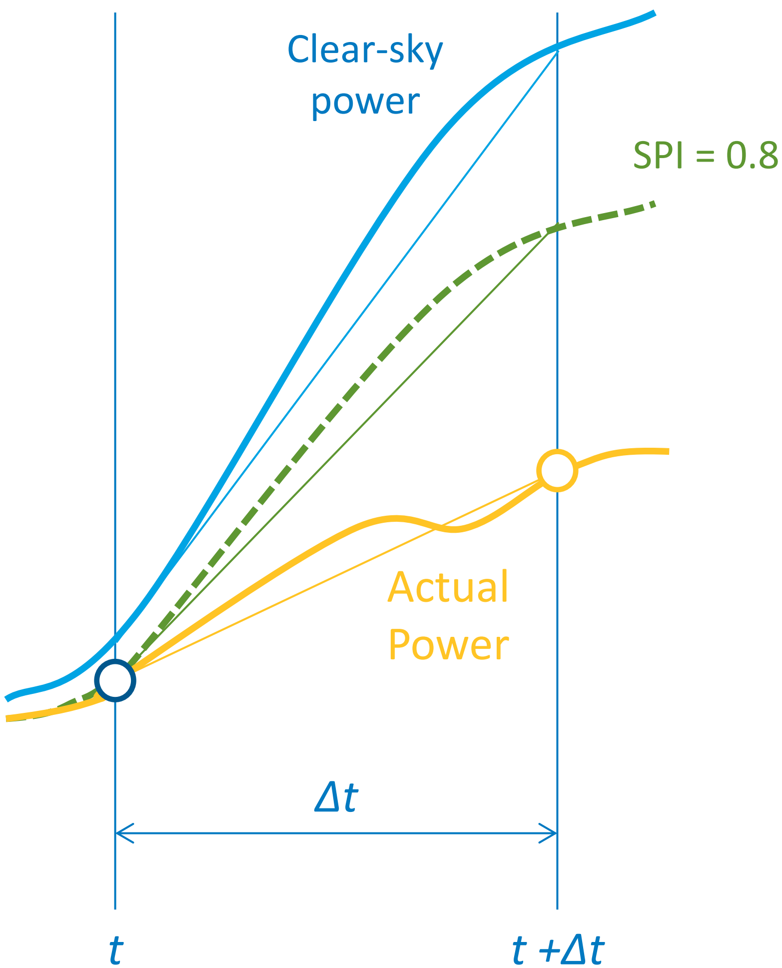


Solar Forecast Error (1/4)



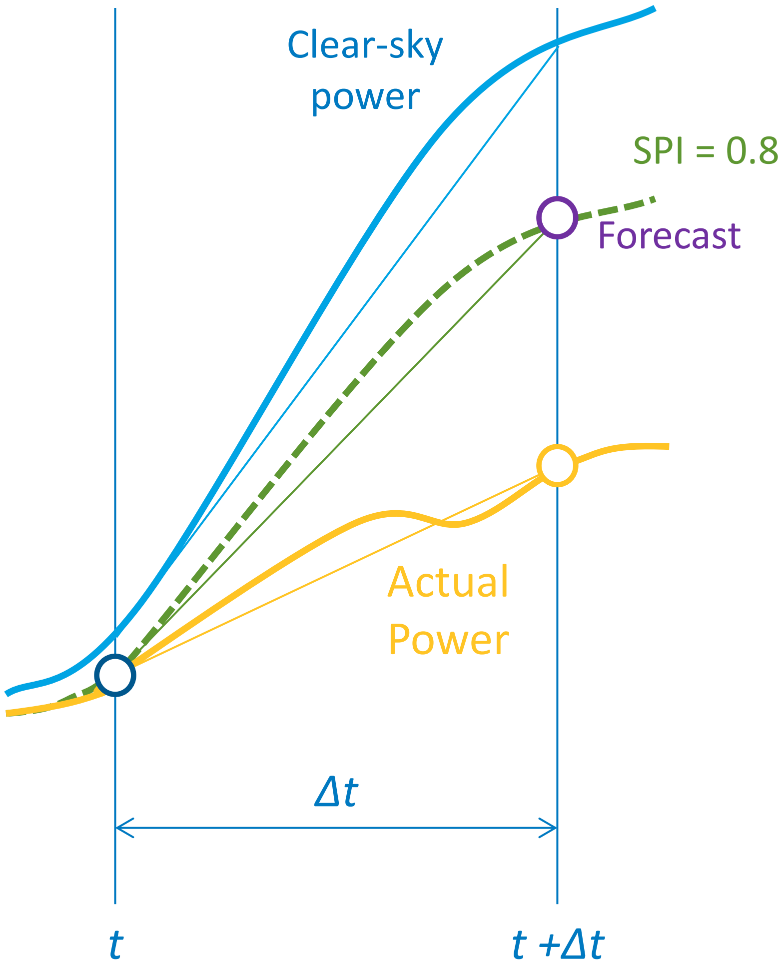
- **Consider time *t* and next time step, *t+Δt***

Solar Forecast Error (2/4)



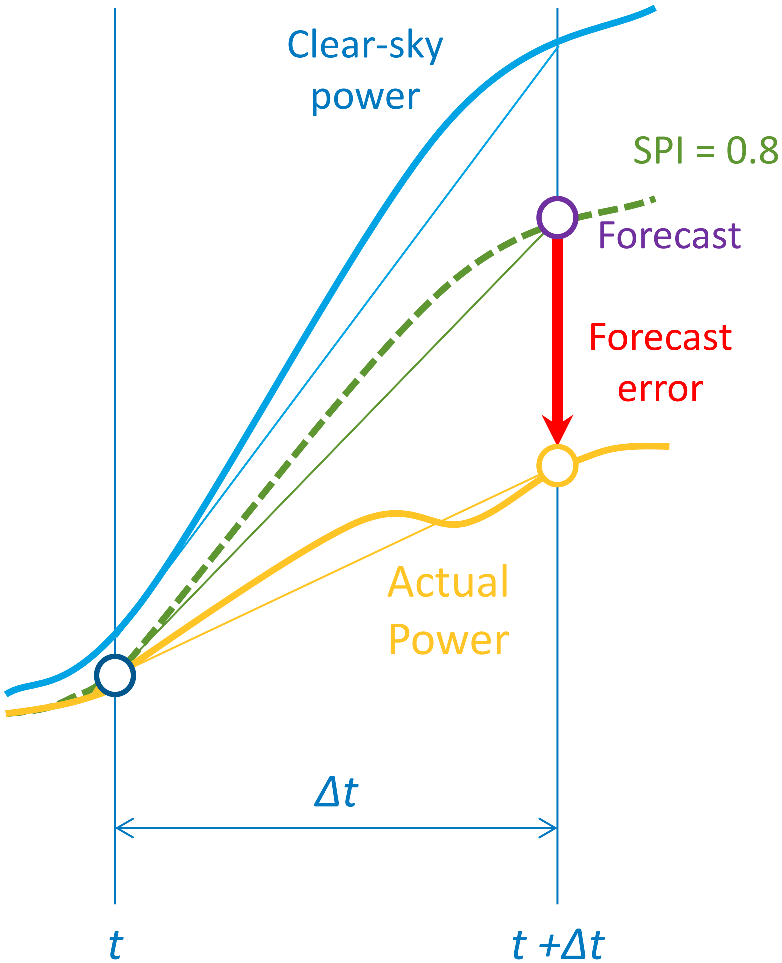
- **Consider time *t* and next time step, *t+Δt***
- **Assume constant SPI for forecast**

Solar Forecast Error (3/4)



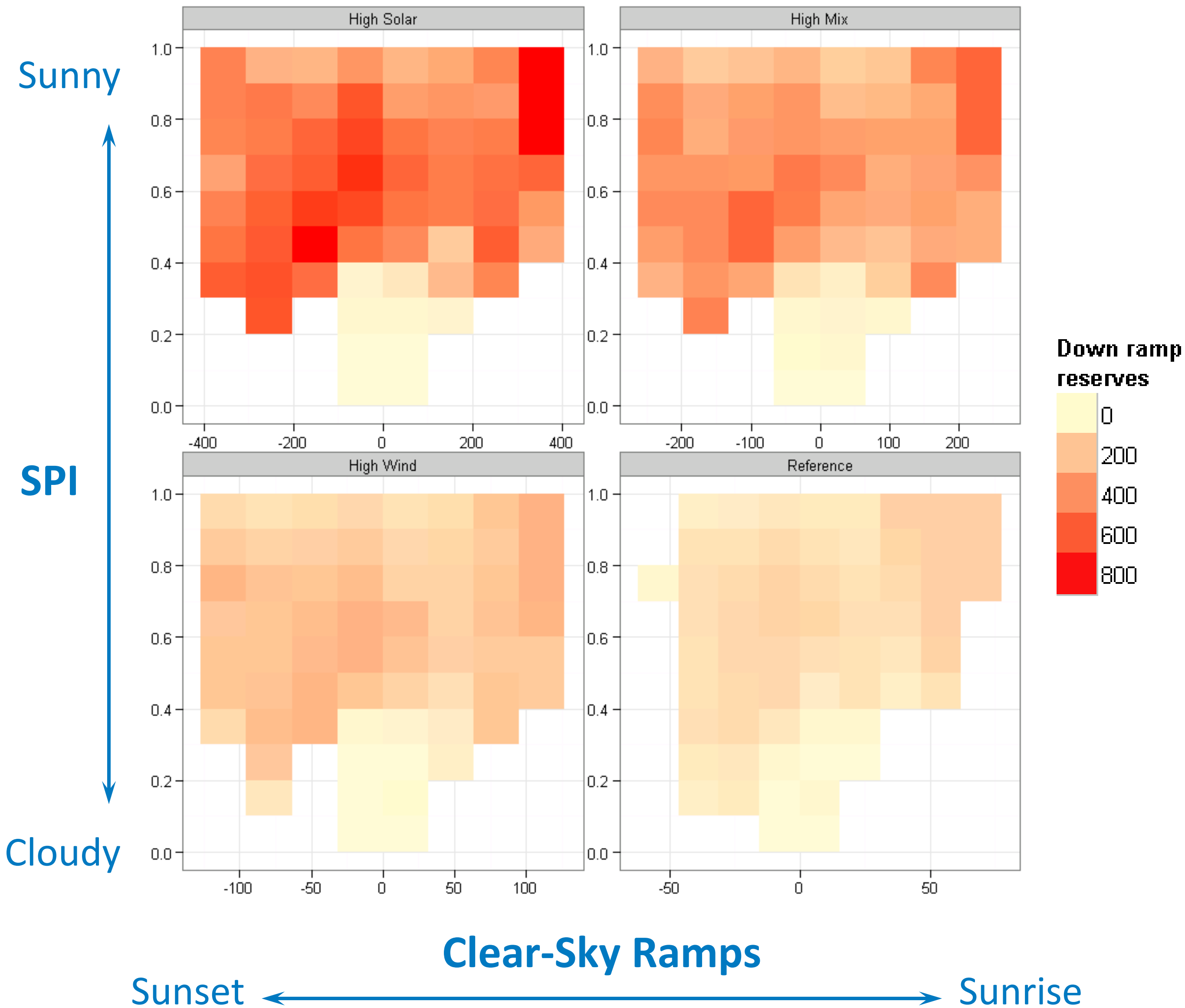
- **Consider time *t* and next time step, *t+Δt***
- **Assume constant SPI for forecast**
  - **Forecast = Power + SPI *ΔClear-Sky Power**

Solar Forecast Error (4/4)

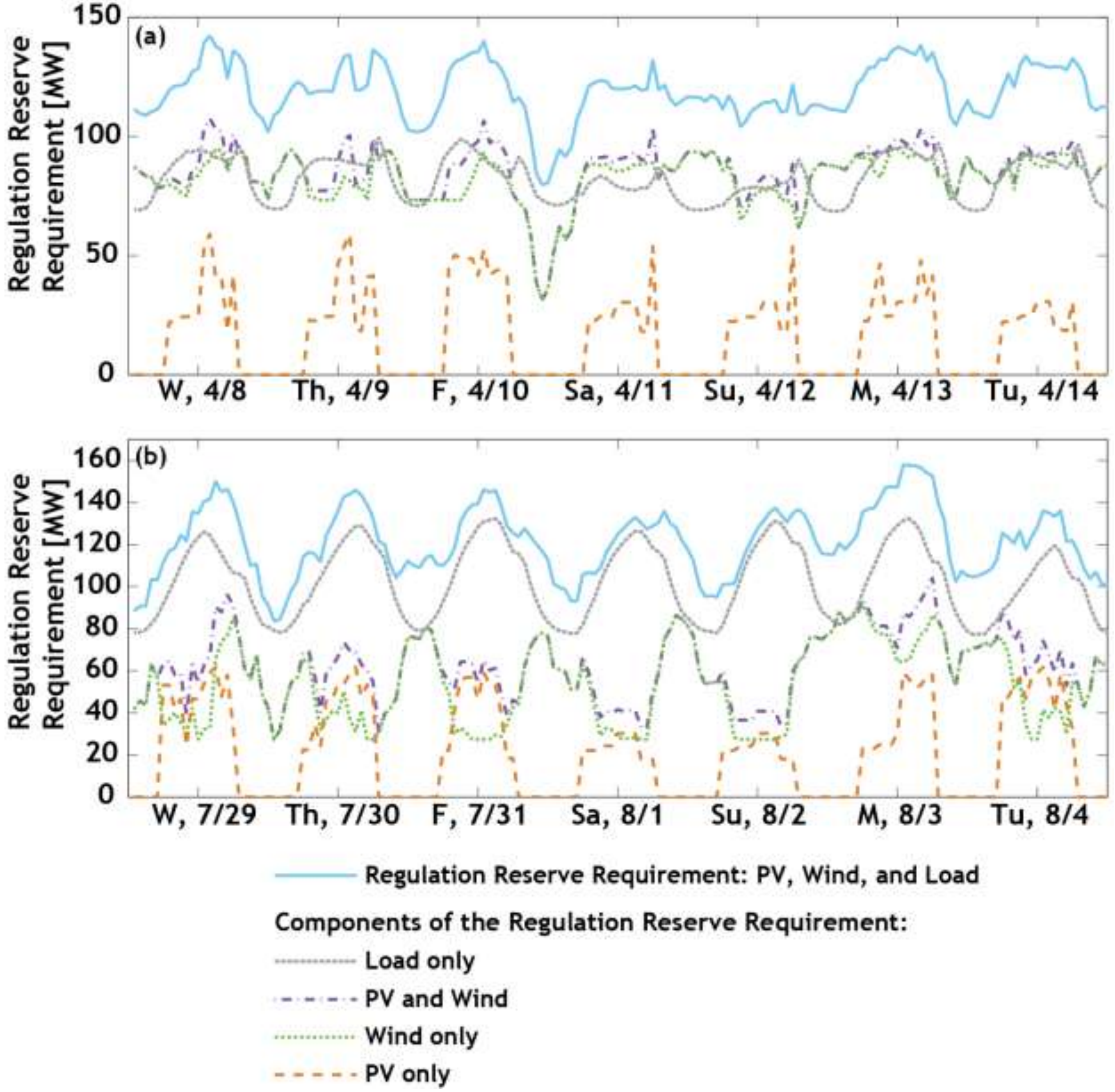


- Consider time *t* and next time step, *t+Δt*
- Assume constant SPI for forecast
  - Forecast = Power + SPI *ΔClear-Sky Power
- Forecast error is the difference
  - Error = ΔPower + SPI *ΔClear-Sky Power

Regulation Reserves for WWSIS-II



Geometric Sum for Regulation Reserve

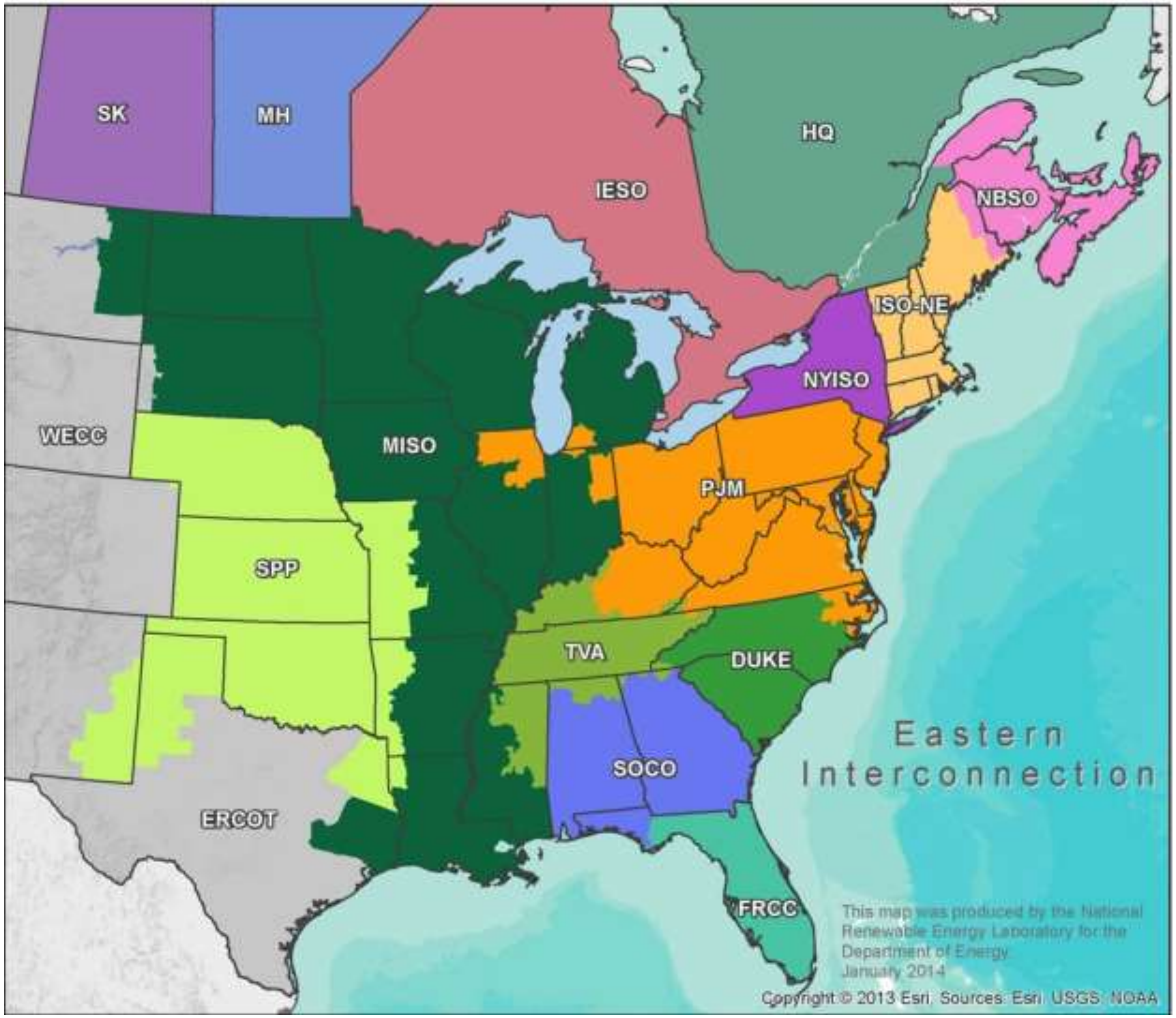


Modeling Reserves: Generator Participation

Reserve provision from within a region.

50% of the ramping capacity (from the following generator types) can provide **regulation**:

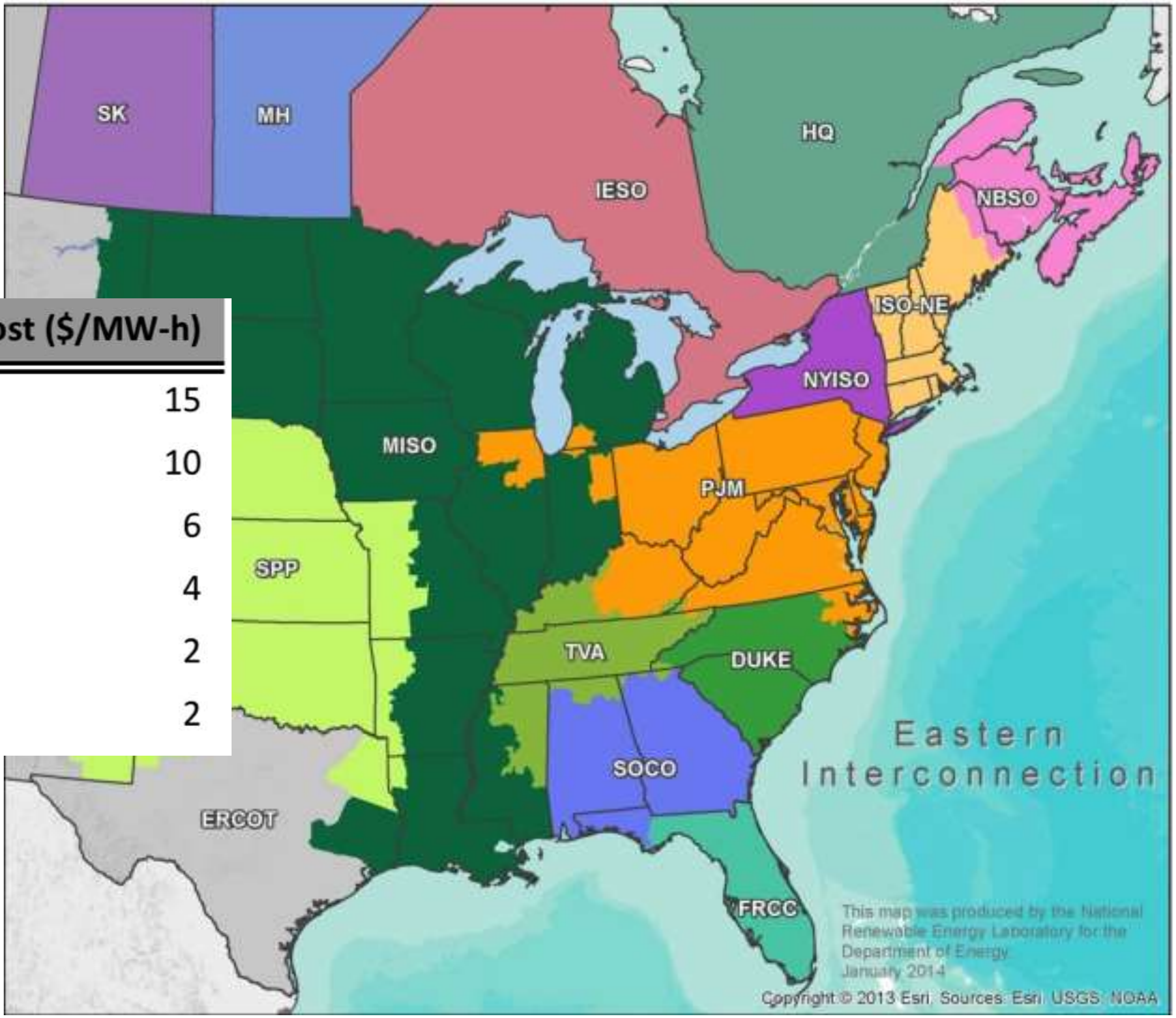
- coal
- combined cycles
- gas/oil steam
- hydro
- pumped hydro



Modeling Reserves: Generator Participation

Regulation wear and tear costs (from PJM Manual)

Generator Type	Cost ($/MW-h)
Supercritical Coal	15
Subcritical Coal	10
Combined Cycle (CC)	6
Gas/Oil Steam	4
Hydro	2
Pumped Storage	2

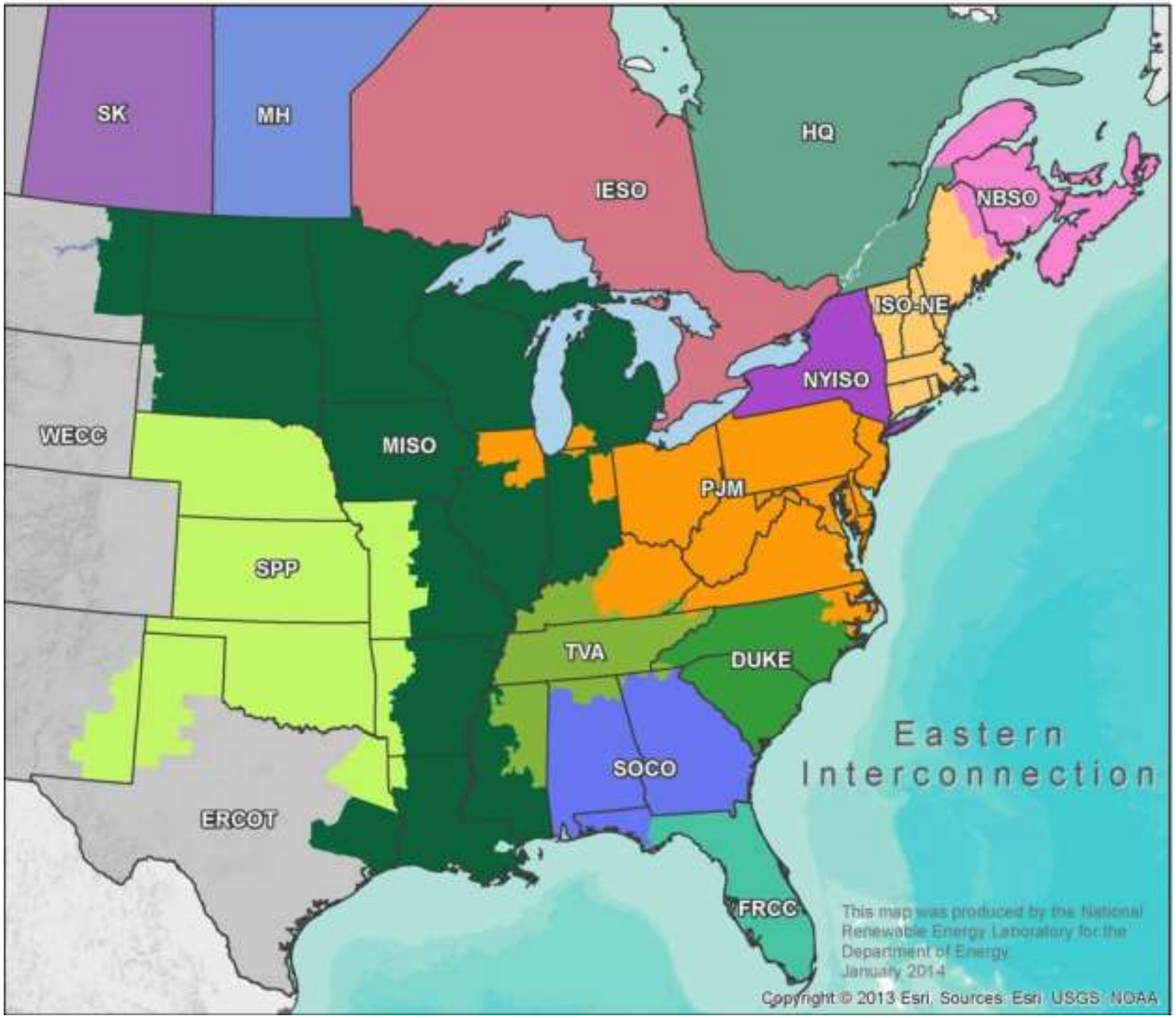


Modeling Reserves: Generator Participation

Reserve provision from within a region.

Generators providing **contingency**:

- coal
- combined cycles
- combustion turbine
- gas/oil steam
- hydro
- pumped hydro



Reserves Next Steps

- **Calculate the reserve requirements** by market sequence step, reserve sharing group, scenario, and type of reserves (February – March)

- **Analyze the ramping capacity**, by market sequence step, reserve sharing group, generator type, and renewable penetration scenario (April-May)
  - Evaluate the impact of the operating characteristics of generators
  - Evaluate the impact of limiting the number of generators providing reserves

- We will be asking for feedback, comments, etc. in late Spring – before the next TRC

Sensitivity Analysis

Purpose

- Identify operational practices that impact production costs
- Test these practices on the ERGIS database
- Compare the production costs across sensitivities

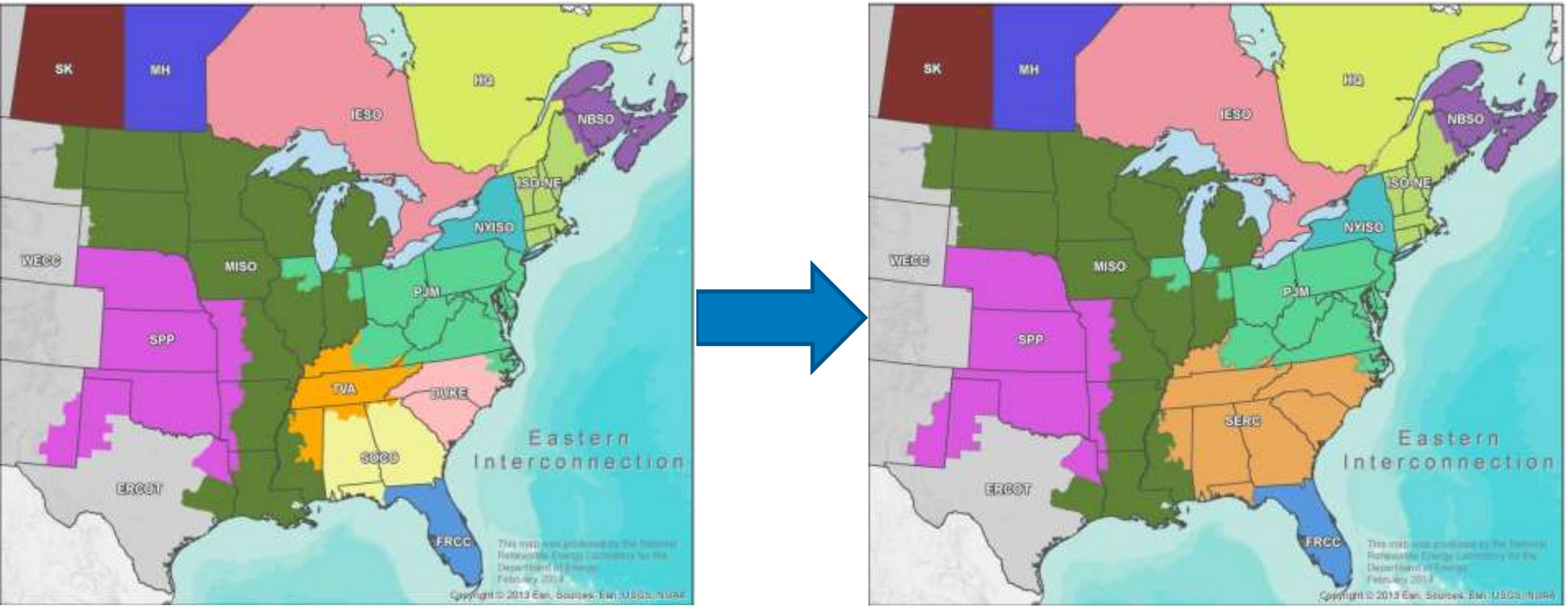
Potential Sensitivities

- **Reserves**
  - Products
  - Sources
  - Sharing
- **Intra-day unit commitment**
- **Self-scheduling**
- **Interchange scheduling**
- **Multi-period look-ahead dispatch in real-time**
- **Demand elasticity**

Reserve

- **Products**
  - Ramping/flex/following
- **Sources**
  - Traditional thermal
  - Flexible thermal
  - Hydro
  - Wind/Solar
  - Demand response
  - Storage
- **Sharing**
  - Southeastern US
  - SPP-SERC
  - Other regions

Reserve Sharing Groups



Unit Commitment

- **Options**
  - No intra-day commitment
  - Recommit every 4 hours
  - Rolling unit commitment
- **Resources that could be recommitted**
  - Combined cycle
  - Combustion turbine
  - Hydro

Self-Scheduling

- By resource type
- Percent of total fleet
- Differences by region

Interchange Scheduling

- **Hourly interchange**
- **15-minute**
- **5-minute**
- **Dynamic scheduling**

Multi-Period Look-Ahead Dispatch

- **Real-time dispatch is informed by future intervals**
- **Look-ahead window?**

Demand Elasticity

- **Assume some level of price-responsive demand**
- **Quantity and price**

4-Month Plan

4-Month Plan

- **2026 Runs**
  - All scenarios
  - Increasing resolution
  - HPC and server
- **Stay flexible and give team time to review data**
- **Options for working group calls to reveal results as they become available**

4-Month Plan

- **May WindPower**
  - Las Vegas, NV
- **June TRC meeting**
  - Washington, DC
- **December TRC meeting**
  - Washington, DC

Contact Us

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